BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 103
NIPSCO 2019 Rate Order

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND, 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: DEC 4 2019

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 ("Petition") 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 ("MSFRs"), and Request for Administrative Notice with the Indiana Utility Regulatory Commission ("Commission"). Petitioner also filed its case-in-chief, workpapers, administrative notice documents, and information required by the 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 with NIPSCO[3]
- Paul S. Kelly, Vice President of Major Accounts with NIPSCO

[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.
[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.

- 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, 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]

Petitions to intervene were granted to the following parties:

- 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")

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[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.
[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.

- 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 appeared and made statements to the Commission.

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

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[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.
[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.
[15] 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.

Industrial Group provided testimony and exhibits from the following witnesses:

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

[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 and filed a Notice of Substitution of Witness on June 11, 2019.
[22] US Steel originally filed testimony of Constance T. Cannady, which was withdrawn on June 25, 2019.
[23] US Steel filed revisions to Mr. Georgis' testimony on March 7, 2019.
[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.

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, US Steel, CAC, Walmart, NICTD, Sierra Club, and the OUCC (the "Revenue Settling Parties") filed a Stipulation and Settlement Agreement on Less Than all the Issues resolving revenue requirement and other miscellaneous issues (the "Revenue Settlement"). On April 30, 2019, the Revenue 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, specifically Paragraph 11.[28]

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, in support of the Rate 831 Settlement, NIPSCO filed testimony of Curt A. Westerhausen; Industrial Group filed testimony of Nicholas Phillips, Jr.; and US Steel filed testimony of Tony M. Georgis.

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, a consultant.

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 Dr. Boerger and CAC's responsive testimony of Mr. Olson and Mr. Wallach.

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[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 IMUG 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 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, the Industrial Group filed reply testimony of Nicholas Phillips, Jr., and US Steel filed reply testimony of Tony M. Georgis.

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

The Commission held an Evidentiary Hearing in this Cause beginning on July 25, 2019, at 9:30 a.m. and continuing through August 5, 2019, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. All participating parties appeared, presented their evidence, and offered their witnesses for cross-examination.

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Based upon the applicable law and evidence presented, the Commission 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% to 21% 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 in 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 15 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

[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.

Rules and Regulations and Standard Contract. 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. New Industrial Service Structure. NIPSCO requests that the Commission approve NIPSCO's proposal for a new industrial service structure as an alternative regulatory plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6. To the extent any other proposals of NIPSCO herein may require alternative regulation, NIPSCO requests that they be approved as an ARP. NIPSCO elects to become subject to the provisions of Ind. Code § 8-1-2.5-6 for purposes of any such proposals. 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.

C. Depreciation Rates. NIPSCO seeks approval to revise its depreciation accrual rates.

D. 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 Environmental Cost Recovery Mechanism ("ECRM") and its Federally Mandated Cost Adjustment ("FMCA") Factor. 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.

E. Accounting Relief. 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; (2) back-up and maintenance demand margins, both for pass back through the Regional Transmission Organization ("RTO") Tracker; and (3) authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired.

F. Demand-Side Management. NIPSCO proposes to exclude from its basic rates and charges all costs associated with its demand-side management ("DSM") program. NIPSCO has also adjusted its usage determinants for energy efficiency ("EE") measures installed

through December 31, 2017, consistent with Evaluation, Measurement, and Verification. NIPSCO has also adjusted its usage upward for EE 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 EE 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.

G. RTO Tracker and OSS Margin Sharing. NIPSCO proposes to update Rider 771 – Adjustment of Charges for Regional Transmission Organization (the "RTO Tracker") to: (1) remove Midcontinent Independent System Operator, Inc. ("MISO") charges and credits and collect 100% of MISO charges that are not included in the Fuel Adjustment Clause ("FAC") through the RTO Tracker; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO Tracker; (3) remove all back-up and maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology.

H. 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.

I. Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with the Commission's orders.

J. 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 ("2019 Forward Test Year" or "Forward Test Year"). The historic base period shall be the 12-month period ending December 31, 2017 ("2017 Historic Base Period" or "Historic Base Period"). The rate base cutoff shall reflect used and useful property at the end of the 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 56% 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 that 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 testified NIPSCO's goal is to be the premier utility in Indiana in every aspect of its performance, including interaction with its customers. 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. Ms. Sistovaris testified that NIPSCO's focus on its customers has resulted in the fewest customer complaints per 1,000 customers at the Commission. She stated that in 2017, NIPSCO's customer care representatives handled 1,376,378 calls. NIPSCO's Average Speed of Answer 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 explained steps NIPSCO has taken to help customers save energy and reduce their monthly bills. NIPSCO has continued to elevate its internal emphasis on EE including enhanced communication with the stakeholders such as governmental agencies, other utilities, and consumer parties. NIPSCO has dedicated staff to EE measures and manages the development and implementation of such measures. NIPSCO's electric EE programs have helped customers save more than one million megawatt hours ("MWh") from 2010 through June 30, 2018. NIPSCO offers a variety of programs for all customer and helps customers manage current energy costs and

to assist NIPSCO in reducing or deferring future generation needs. NIPSCO's EE 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 EE weatherization program to both NIPSCO gas and electric customers and proposed a low-income appliance replacement program in its electric EE 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 to advance low-income assistance and weatherization programs.

Ms. Sistovaris testified that NIPSCO is filing this case to: (1) reflect the evolution of the market for electricity for NIPSCO as well as for its largest customers in NIPSCO's service structure; (2) reflect in base rates the recent capital investments into NIPSCO's electric system, including infrastructure modernization and environmental controls; (3) revise its depreciation rates to reflect the most recent information regarding planned retirements of its generating units; and (4) 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 explained that NIPSCO is 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 transforming toward increased reliance on gas-fired and renewable generation as reflected in the MISO markets.

Ms. Sistovaris stated that regulatory restrictions and environmental costs will increase NIPSCO's cost of producing energy, which will impact generation mix, customer demand, NIPSCO's profitability, and NIPSCO's cash flow. NIPSCO is also addressing compliance with regulations that address the handling and disposal of coal combustion residuals ("CCRs") and may 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 are not limited to: (1) installation of ground water monitoring facilities at Bailly Generating Station ("Bailly"), Michigan City, and Schahfer; (2) installation of remote ash conveying facilities and material management areas at Michigan City and Schahfer; (3) and closure of the landfill pond at Schahfer 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.

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 notice provided to residential customers within 45 days of the filing of NIPSCO's Petition.

B. Michael Hooper. Mr. Hooper testified that by filing this case, NIPSCO 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-year plan.

He also explained why NIPSCO is requesting a change in rates at this time. First, NIPSCO seeks 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 megawatts ("MW") 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. 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 stated that if the economics continue and NIPSCO does not respond, there is a high probability that more industrial load will leave the system and with a low likelihood that it would return, at least in the near term.

Mr. Hooper testified that NIPSCO's coal-fired generating units have seen decreased usage 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 baseload find themselves being the marginal units. He stated that ramping up and down aging coal units causes increased maintenance costs because the units were not designed to operate in that manner. In addition, the recent responses to NIPSCO's Request for Proposals ("RFP") 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. 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 because 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 generation assets. Second, it assures 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, 2030 is not so far into the future that too large a distortion will take place.

Mr. Hooper testified NIPSCO did not include in the proposed depreciation accrual rates any of the costs related to certain Asset Retirement Obligations ("ARO") that must be performed in compliance with the U.S. Environmental Protection Agency's ("EPA") CCR Rule. He explained that the federal regulations underlying the AROs 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 accumulated deferred income tax ("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 generation assets increases the speed at which excess ADIT is returned to NIPSCO's customers.

Mr. Hooper described NIPSCO's derivation of its proposed revenue allocation. He stated that NIPSCO began with a fully allocated cost of service study ("ACOSS") and then developed rates for NIPSCO's Rate 831 customers at parity utilizing the proposed industrial service structure and allocating 184.556 MW of demand at the meter to the industrial class. NIPSCO then allocated the additional revenue requirement from this case over all customer classes equally, resulting in a rate increase for all other customer classes of 11.76%. He stated that this methodology was chosen to avoid rate shock to its Residential customers and 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 its proposed rates: (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 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 ACOSS, 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. However, noting that the currently effective monthly customer charge is $14, in the spirit of gradualism, a $17 per customer per month charge is an appropriate step.

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 COSS 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 including numerous meetings with the representatives of the settling parties to its last electric rate case to inform them about this filing and the issues driving it and to listen to any suggestions or concerns. 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. Paul S. Kelly. 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. He stated that NIPSCO's large industrial customers utilize energy intensive processes, are sophisticated market participants, participate in energy markets globally, and compete on the basis of price globally. NIPSCO believes that now is the time to address the needs of its large industrial customers for a market-sensitive rate structure while it simultaneously addresses its on-going generation needs. He stated that in its 2018 IRP, NIPSCO performed analyses for each of its coal-fired units that evaluated the ongoing operations versus retirement and replacement under various potential future scenarios. NIPSCO used many 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 this filing requires its largest industrial customers to remain as NIPSCO's retail customers, while also providing more market choices and is 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 before the Commission (Cause No. 45071), which sought treatment of WCE as a Qualifying 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 reduce their firm loads. He stated that some large customers, like BP, may utilize new or existing cogeneration systems to reduce their firm requirements, and 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, more economic locations outside Indiana. 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 MW. 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 MW, 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.

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 ten MW; (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 ten MW of Tier 1 firm service. Tier 1 rates were designed based on approximately 184 MW (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. Tier 1 is 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 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 an 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 Locational Marginal Price ("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 North American Electric Reliability Corporation ("NERC")/Critical Infrastructure Protection ("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 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 cogeneration 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. 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 with long useful lives. Considering these issues, he stated the five-year contract period provides a reasonable level of certainty for NIPSCO and its customers in moving to a structure that provides more market choices for Rate 831 customers.

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 and 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% 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 (nine premises) have also taken service under Rider 775. Of those 15 customers, four have less than ten MW 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 ten customers expected to take service under NIPSCO's new Rate 830 including the four below ten MW 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 MW 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 ACOSS allocating 184.556 MW (measured at the customer meter) of NIPSCO's fixed production cost to Rate 831's Tier 1 service for the five largest industrial customers (or 189.794 MW 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 MW 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 MW, 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 NIPSCO recognized not all of its largest industrial customers would be interested in the market-sensitive service under Rate 831. As such, NIPSCO designed Rate 830 to provide an industrial service that is similar to the current Rate 732, with a few exceptions. He explained 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 by Ind. Code ch. 8-1-2.5 for approval of an ARP. 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 markets. 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 explained that NIPSCO is currently implementing the preferred plan from its 2018 IRP for best serving its customers with generation capacity and that to the extent 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 customers will be paying the market rate for energy and will be economically incented to adjust their consumption based on market price signals.

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 country 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 NIPSCO's 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 50% 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 NIPSCO 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 NIPSCO provided information for the Historic Base Period and the period beginning January 1, 2018 and ending December 31, 2018 (the "2018 Budget Period"), for comparison purposes. She stated NIPSCO 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 and the normalization and annualization of these test periods. NIPSCO elected to proceed under the Commission's 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 NIPSCO 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 were 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, and 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 if the Commission does not approve NIPSCO's proposed change in service structure. The reference to "A2" represents the attachments for a second alternate revenue requirement if the Commission does not approve NIPSCO'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 demolition study's AROs.

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 Bailly retirement 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 herein proposed, as explained by NIPSCO 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 that 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. 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 by recognizing that NIPSCO has continued to collect 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 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 AROs are new, estimated costs to close the ash ponds have generally not previously been included in NIPSCO'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 are 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) includes the recovery of anticipated demolition costs, with the exception of costs required to comply with the AROs. She stated that NIPSCO has excluded the costs to comply with the AROs 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. She stated that NIPSCO will thus not be recovering through depreciation accrual rates approved in this Cause the costs to comply with the AROs.

Ms. Shikany testified NIPSCO is filing an alternate demolition study to demonstrate how inclusion of the costs to comply with the AROs in the demolition studies would impact the study results. She stated that inclusion of the costs to comply with the AROs 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 AROs 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 coal-fired generation at Schahfer by 2023 and Michigan City by 2028, Ms. Shikany stated 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 AROs 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. An increase in annual depreciation expense of this magnitude would result in a significant increase in customer rates.

Ms. Shikany explained that in order to mitigate the effects of such a significant rate increase, NIPSCO is proposing to recover 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 asset's anticipated physical retirement date, 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 AROs, demolition costs will continue to be recovered through rates as a component of depreciation rates. The costs to comply with the AROs,

however, will not be recovered through depreciation rates approved in this rate case under this proposal. The costs to comply with the AROs 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 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, NIPSCO should be compensated by earning a return on remaining net book value in a future rate case. She stated that in order to mitigate NIPSCO'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 Generally Accepted Accounting Principles ("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 its 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 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 NIPSCO 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 to increase reliability and flexibility. 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 NIPSCO 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 are expected to provide benefits over extended periods of time and not just in the period in which the costs are incurred, NIPSCO 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. NIPSCO 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 ("URT") 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 that changed the income statement presentation of Pension and Other Post-Employment Benefits ("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 GAAP. She stated that NIPSCO included the balance of the Prepaid Pension Asset as a component of its overall WACC.

Ms. Shikany provided separate, detailed explanations for each of NIPSCO's proposed pro forma adjustments to its proposed capital structure, and she 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 (the "2018 AFP") for its electric utility covering the 2018 and 2019 plan years, which is the underlying basis for its rate request; 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 operation and maintenance ("O&M") budgets and longer-term financial plans. He explained the process that NiSource and NIPSCO use 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.

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. 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 five years, which demonstrates a high level of historical capital budgeting accuracy. 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 then 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 also described the major components of NIPSCO Electric's tax expenses other than income taxes to be property taxes, payroll taxes, public utility fees, and URTs. 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 also 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. Patrick N. Augustine. 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. 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 other factors, such as the loss of work for employees and the reduction of property tax base for surrounding communities, also factored into the 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 retirement combinations and that the projected future capital and operating costs for the affected units were modeled by Charles River Associates ("CRA") in the Aurora production cost and utility portfolio model. He explained that the economic analyses ultimately compared 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, and thus, the analysis assumes that return of and on capital is recovered in all cases.

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 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 of the scenarios, retirement of all coal units (Retirement Combination 8) and replacement with a model-optimized selection of 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 Retirement 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 Retirement 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 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 NIPSCO's customer service and electric reliability programs, described the investments NIPSCO has made to its generation, 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 three 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 department or cost center managers 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, 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 provided tables identifying the associated capital costs. 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 assist NIPSCO in meeting increasingly stringent air emissions requirements. Mr. Hooper also identified other capital improvements to NIPSCO's generation fleet since its last base rate case not already included in either the FMCA or ECR tracking mechanisms, and explained that those improvements are 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 NIPSCO'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%. 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 baseload 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.

Mr. Hooper addressed NIPSCO's base cost of fuel and coal inventory levels. He testified that the adjusted retail jurisdictional cost of fuel in the Historic Base Period reported in 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 Attachment 4-B-S2, RB Module for the Historic Base Period was $80,046,953, and that it was reasonable and consistent with NIPSCO's desire to have adequate fuel supplies on hand while balancing the costs associated with maintaining coal inventory.

Mr. Hooper discussed NIPSCO's safety culture and described how NIPSCO and its consultant derived a plan to deliver human performance based error reduction 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 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 by forming cooperative contractor safety committees for both its generation and field operations teams. He added that NIPSCO's focus on cooperation and safety has resulted in strong safety performance from its contracted teams. He testified that NIPSCO Electric 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.

Mr. Hooper described NIPSCO's transmission and distribution systems. He explained that NIPSCO's transmission system consists of approximately 353 circuit miles of 345 kilovolt ("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), 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 138 kV interconnections with Ameren and International Transmission Company and a single 765kV interconnection with Pioneer Transmission. He stated NIPSCO's distribution system serves 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 four 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 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 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 capacity and reduce risk. Mr. Hooper explained that while significant investment had also been made in multi-value projects ("MVP") 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 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, which primarily include storms or severe weather 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 five years.

Mr. Hooper testified about the programs NIPSCO uses to support transmission, distribution, and substation reliability and ensure compliance with NERC standards. These programs include wooden pole inspection, vegetation management programs, and periodic inspections and maintenance of transmission lines and structures, substation equipment, protective relay systems, 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. 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 "unknown" outage cause. Linemen, 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, more accurately perform analytics on 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 enhance customer reliability by incorporating newer regulators and enhanced tap changers that reduce contact wear and premature failure. He 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 continues its "Worst Circuits" and "Worst Taps" Programs whereby circuits and taps with the worst performance values and outages are assessed and recommendations for improvement are 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 that investment in an Enhanced Outage Management System expected to be in service in early 2019 to improve customer experience by providing faster restoration and more accurate communication of estimated time of restoration during outages.

Mr. Hooper supported a number of proposed adjustments found in Petitioner's Confidential Exhibit No. 20-S2. He testified that Adjustment OM 2A-17 increases non-labor Storm expense for the Historic Base Period by $1,336,602 to approximate a five-year average of storm expense, adding that both five- and seven-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 five-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 flue gas desulfurization ("FGD") facility will no longer be required to operate and 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: (1) a $1.9 million budget reprioritization decision; (2) a $2.4 million pull forward of 2018 budgeted dollars for the pre-purchase of materials, and; (3) a $1.1 million reduction in planned outages. He explained that while operationally advantageous, they were isolated opportunities and should 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 still 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.

Mr. Hooper described Adjustments OM 2G18, OM 2G-19, and OM 2G-19R regarding proposed adjustments to NIPSCO's Vegetation Management expenses. 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 are identified, and remedial work is performed. When compared to the same time frame (January through June) as last year, NIPSCO has experienced an overall reduction in tree related outages and 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 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. As such, Adjustment OM 2G-19R was made to increase vegetation management expense by $5,720,500 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 compared to the previous contract cost of $19.90 per ticket. He stated the incremental cost per ticket was then multiplied by the number of locates in the 12-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. These incremental 811 volumes were multiplied by 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 megawatt hours produced across NIPSCO's remaining units. Mr. Hooper stated 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 explained that the Long Term Service Agreement ("LTSA") expenses for Sugar Creek were incurred based on the unit's Run Time. He stated 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 MATS compliance costs associated with Bailly have been removed. Mr. Hooper 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 testified 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 EPA's CCR Rule and MATS. He summarized the Environmental Compliance Projects that 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 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 NAAQS into its planning process, including its 2016 and 2018 IRPs and that each NIPSCO generating unit is equipped with controls to reduce emissions and 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. He also described MATS, which was issued to reduce mercury, other non-mercury metals, and acid gas emissions from coal- and oil-fired generating units, and required compliance at four NIPSCO 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 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 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 IRP GHG analysis 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 EE and DSM; 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. 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 generating facilities applicable 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, which 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 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 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. 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 regulations regarding CCR disposal facilities to standards equivalent to the CCR Rule in 2017. He stated that 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 NIPSCO's compliance with the CCR Rule's requirements 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. 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 cost estimates and other information for the CCR compliance projects approved in Cause No. 44872.

Mr. Carmichael next explained that NIPSCO is not proposing to recover ARO 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 the 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.

Mr. Carmichael also explained that NIPSCO has a total of 13 CCR surface impoundments and one CCR Landfill at Bailly, Schahfer, and Michigan City that are subject to the CCR Rule and/or RCRA. He 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 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. 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, 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 outlined the number of CCR impoundments and landfills at each NIPSCO generating station and the currently-anticipated method of closure for each, which are 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 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 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, which include 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 federal and state obligations related to asbestos containing material at Bailly, Schahfer, and Michigan City.

Mr. Carmichael addressed the interplay between environmental regulation and NIPSCO's resource planning. 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. Notably, the CCR and ELG Rules require significant capital expenditures for compliance. Future anticipated regulation of GHG emissions and updated CSAPR and ozone NAAQS regulation on Schahfer Units 17 and 18, were also specifically considered.

Mr. Carmichael testified about key assumptions NIPSCO 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 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 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. 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. Andrew S. Campbell. 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 ("PRMR"). If NIPSCO does not have sufficient Capacity Resources to cover its forecasted peak demand and PRMR, 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 NIPSCO's MISO-related costs.

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"). In addition to its PPA wind purchases, NIPSCO recovers cost of capacity and energy purchases made through its 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 FAC proceedings consistent with NIPSCO's treatment of its wind PPA purchases approved 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 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 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 then described proposed Rate 831 – Industrial Power Service – Large. He stated that as proposed, Rate 831 is available to industrial customers currently taking service under Rates 732, 733, and 734. Rate 831 has three 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. He stated that customers must demonstrate or document, to NIPSCO'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 NIPSCO'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 an 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 PRMR with MISO. He explained that by September 30 of each year, NIPSCO will share with each Customer its PRMR, forecasted Coincident Peak demand, and supporting documentation. 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, NIPSCO is responsible for all forecasted needs and its forecast methodology, which is subject to audit and due diligence by MISO. He indicated NIPSCO 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 then described Tier 1, Tier 2, and Tier 3 service under Rate 831. Tier 1 is a firm service served by NIPSCO's generation and market activity in MISO. The default Contract Demand election is 30,000 kilowatt ("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.

Mr. Campbell explained that the Customer's Tier 2 Contract Demand is the Customer's PRMR using NIPSCO'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.

Mr. Campbell testified that 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.

Mr. Campbell stated that the Customer may elect a Tier 3 Contract Demand up to the Customer's PRMR using NIPSCO'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. Mr. Campbell explained that 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.

Mr. Campbell explained that 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 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.

Mr. Campbell stated that 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 explained the difference between Tier 2 and Tier 3 service under Rate 831. He stated that 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 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. He stated that this could include procuring all or a portion of expected energy needs in the Day-Ahead Market or entering into third-party bilateral energy arrangements (alternative generation). Customers will also be able to procure capacity through the MISO PRA or 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 NIPSCO-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 individual settlement statements with MISO, other customers will be insulated from activity of Tier 3 customers. Furthermore, any additional charges related to the activity of 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 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, Tier 3 customers receive the full benefits and risks associated with activity in the MISO Market.

Mr. Campbell addressed how curtailments will change under Rate 831. He stated 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 an LMR with MISO. There is no change in the obligations associated with the LMR registrations from today under current Rider 775. He added that Rate 831 is written in a way that if MISO's LMR rules change, 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. He stated that 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. Addressing curtailment notice requirements, he indicated that NIPSCO will dispatch Customers for MISO curtailments in accordance with the limitations specified under Rate 831 and NIPSCO'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 NIPSCO 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 Tier 2 Customers and be priced at the Day-Ahead LMP at NIPSCO's applicable Load Zone. NIPSCO will continue to offer the energy produced by its generation facilities into the MISO Market, and it will 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. He added that Rate 831 will simply place the burden of optimizing customer specific loads on customers electing service under non-firm Tier 3 and that NIPSCO will continue to optimize remaining retail customer load.

Regarding 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 the PRMR method as discussed above to be consistent with the proposed Rate 831. He stated that Tier 3 Customers will be able to 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 stated that as proposed, new Rate 830 – Industrial Power Service – Small is similar to existing Rate 732 and is available to Industrial Customers taking service at Transmission or Sub-transmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Sub-transmission 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 kW and not exceed 25,000 kW. 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 NIPSCO'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 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 – 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 options of curtailable service: (1) Tier 2 is "curtailments and/or MISO PRA capacity;" and (2) Tier 3 is "curtailments, 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. He stated that in either circumstance, the load is covered from a MISO Resource Adequacy perspective.

Mr. Campbell explained NIPSCO's change in the Resource Adequacy 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 if NIPSCO were to include the charges in base rates, there would be a misalignment unless NIPSCO ran a COSS 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, he added that NIPSCO is proposing to update the allocation.

Mr. Campbell described and supported proposed pro forma Adjustment REV-8A-19R and FP-2-19R. He stated that NIPSCO liquefied less gas in the Historic Base Period (January 1, 2017 – December 31, 2017) compared to the volumes expected going forward. The five-year average of actual gas liquefaction was 1,166,142 MCF. NIPSCO believes the five-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. She supported the O&M expenses associated with the Corporate and Operating services provided by NCSC to NIPSCO, and she 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. 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 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 per month. NCSC makes the payment to the vendor, and the charges for the services are recorded directly on the affiliate's books.

Ms. Taylor testified NCSC has executed an individual Service Agreement with each affiliate that is routinely updated so that all affiliates that receive service from NCSC are subject to the same Service Agreement, which 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 started on January 1, 2009.

Ms. Taylor testified NCSC is regulated by FERC. Pursuant to FERC Order No. 684, 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

and 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, which issued no adverse comments to NCSC related to its allocation methods. She stated that NCSC continues to use the allocation methods subject to that 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 five-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 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) a 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: (1) market-driven base compensation; (2) market-driven performance adjustments/merits; (3) long- and short-term incentives; (4) profit sharing; and (5) health and welfare benefits.

Ms. Cartella explained that NiSource employs compensation and benefits consultants to assist in determining employee compensation across the NiSource Operating Companies. Mercer LLC assists NiSource in setting competitive salary ranges and in evaluating and recommending changes to employee health and welfare benefit plans. Aon Hewitt Associates 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. 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, 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. 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 Associates demonstrated that the overall, employer-paid value of NIPSCO's benefits plans is 3.1% lower than the average of a comparator group of 11 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 and remediating certain NIPSCO Electric generating stations (collectively, "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 personally inspected each generating station 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 if NIPSCO were to include costs related to the AROs.

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. The estimate also assumed all below-grade foundations would remain and the below-grade excavated areas would be used for landfill space for 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 prepared the demolition cost estimates using standard and accepted estimating techniques consistent with available data and industry experience, and that the assumptions listed in each report are reasonable and the estimates are accurate based on the assumptions made. The demolition cost includes environmental remediation, indirect costs, contingency, and positive salvage value. Burns & McDonnell estimated the total net cost to demolish each station, net of positive salvage and excluding costs related to the AROs, to be:

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 depreciation study's methods and procedures 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 provided 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 phase one, 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 phase two, 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 NIPSCO'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. NIPSCO 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 NIPSCO during the study period.

Mr. Spanos testified that he used the life span technique to estimate the lives of significant facilities such as production plants. 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 the life span technique has been presented to and accepted by many public utility commissions 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 NIPSCO'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 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 costs 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 two and seven 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 AROs that must be performed in compliance with the federal CCR 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 ADIT 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: (1) 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; (2) various tax rate changes including the most recent TCJA; (3) certain limitations on the amount of the federal income tax deduction that may be taken on certain categories of expense; (4) reduction in tax expense for amortization of ITC; and (5) 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: (1) the non-deductibility of the Indiana URT; (2) the excess deferred taxes resulting from the decrease in the state tax rate from 8.5% to 5.625%; (3) the non-deductibility of certain expenses; and (4) AFUDC.

Mr. McCuen explained NIPSCO'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 NIPSCO'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 NIPSCO'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: (1) decrease to federal and state income taxes to reflect tax expense on pro forma taxable income at current rates; (2) increase to tax expense due to the changes in the proposed service structure at current rates; and (3) 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 Electric 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%, and that a point estimate at the midpoint of this range, or 10.80%, is the appropriate cost of equity to apply in this case. Based upon this finding, he determined that NIPSCO's WACC is 7.02%, 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 well-recognized analytical models to the market and financial data of the selected proxy group companies: the Discounted Cash Flow ("DCF") 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. Finally, to confirm the reasonableness of the cost of equity estimates yielded by these market-based models, he 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 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 that NIPSCO 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. To confirm the reasonableness of NIPSCO'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 that NIPSCO's proposed equity capitalization level, based upon investor-supplied sources of capital, as of December 31, 2019, is 57.11%, 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%, which is the cost of equity he is recommending in this proceeding and the cost rate for Long-Term Debt is 4.97%, which is based on NIPSCO'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 baseload 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 baseload/temperature-sensitive load normalization procedure approved in the 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.

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.

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 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 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 occur regularly and 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 is 1.8% for the residential model, 1.5% for the commercial model, and 3.8% for the more volatile industrial model.

Q. Bickey Rimal. Mr. Rimal testified in support of the ACOSS used in conducting NIPSCO's electric COSS. 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 related to NIPSCO's ACOSS. He stated that two main sources of the data and inputs were utilized: (1) the historical books and records of NIPSCO including the general ledger and engineering systems; and (2) 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-ACOSS 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. Dr. Gaske sponsored the class COSS and rate design, and 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 COSS. 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., 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 discussed various cost allocation principles, factors influencing the cost allocation framework, and the methodology and basis used in NIPSCO's COSS. He noted that Customer Costs are incurred to extend service to and attach a customer to the distribution system, meter 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 vary with the amount of kWh sold to customers. For example, base fuel rates and some production operating costs that tend to vary with the amount of energy produced are included in the COSS. 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, which 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 12 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 described other adjustments to the test period demand and energy determinants. 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 non-coincident peak 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 fixed cost contribution is better than none, NIPSCO is proposing to provide a 70% 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 class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS for: (1) the 700 series rate classes that were forecasted to be in effect during the test year; and (2) the proposed 800 series rate classes, 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 NIPSCO'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 used to set rates in this proceeding.

Dr. Gaske testified that NIPSCO 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%. 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 proposed rates. 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 Back-up, 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 831 customers will manage 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 Back-up 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 customer impacts of the proposed rates. He 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 proposed Rate 831, there is no longer a need for the interruptible Rider 775, which NIPSCO 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 summarized each of NIPSCO's Proposed Rates including a discussion of each rate's components and an overview of the changes made and the rationale for making them. 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 Sub-transmission voltage whose plants are located adjacent to existing electric facilities having Transmission or Sub-transmission 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 kW and not exceed 25,000 kW. Those Premises served under Rates 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 NIPSCO'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 or Back-Up Service). This rate is further discussed by 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 Sub-transmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Sub-transmission capacity sufficient to meet the Customer's requirements. Customers shall contract for a definite amount of electrical demand, which shall not be less than 10,000 kW for a five-year term. Rate 831 has three 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 NIPSCO'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 NIPSCO'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 ("AAQFPTC") (Tier 1, Tier 2, and Tier 3), and applicable Riders. This rate is further discussed by 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 NIPSCO's electric supply lines. 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. NIPSCO is proposing to roll the Electric TDSIC tracker rate base as of December 31, 2019, into the revenue requirement. As such, 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 ACOSS model and allocated by energy at the generator, as discussed by 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 URT on customer bills instead of including it in the calculation of the factors in this Rider, as discussed by 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. 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, as discussed by witness Campbell. NIPSCO is proposing to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider, as discussed by witnesses Shikany and McCuen. The production and energy allocators utilized for purposes of allocating the costs inside

[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 URT on customer bills instead of including it in the calculation of the factors.

of this Rider will be updated based upon the ACOSS. 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 URT 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 ACOSS. 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 NIPSCO 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, as further discussed by 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 an LMR; unless MISO rules change and do not permit load used by NIPSCO as an LMR 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 NIPSCO to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with NIPSCO 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 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 an LMR; unless MISO rules change and do not permit load used by NIPSCO as an LMR 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 NIPSCO to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with NIPSCO acting as the Market Participant for the Customer. Customers who do not qualify as an LMR 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 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. He 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 12 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 $31,507,991 in 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 NIPSCO'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 that 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. 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 NIPSCO'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 when 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. 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 NIPSCO 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. 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 kV 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 kV Amps is the 2019 forecast. Proposed Rate 831 has three tiers of service 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 Tiers 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, Tier 2 and 3 energy was adjusted. For Customers with a Tier 1 load factor below 99%, the adjustment was made at the same proportion as their 2017 Tier 1, 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 Ind. Code § 23-1-43-1) and having the same qualifying service voltage, IDR meters with five-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. No adjustments were made to the forecasted reactive kV Amps.

Mr. Westerhausen described NIPSCO's proposed updates to the tracker allocators. He explained that Rate 831 contains three tiers of service with the current trackers applicable to 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 Tier 2 and Tier 3 transmission portion of Rate 831. The demand allocators are based on the mitigated allocation of the ACOSS revenue. The Rate 831 allocation was adjusted to reduce the ACOSS revenue down to the revenue associated with Tier 1. The energy allocators are based on the sales allocator from the ACOSS. The Rate 831 sales are strictly Tier 1 sales so no adjustment is required. He explained that 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 sub-transmission allocation of the revenues in the ACOSS. 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 ACOSS. No adjustments were made for Rate 831. The tracker allocations are provided in Attachment 19-F.

7. OUCC Case-in-Chief.

A. Michael D. Eckert. Mr. Eckert recommended that NIPSCO's Phase 1 revenues should be decreased by $30,630,526 or 2.14% based on a WACC of 6.25%, and NIPSCO's Phase 2 revenues should be decreased by $10,233,307 or 0.71% based on a WACC of 6.27%. He reviewed NIPSCO's test-year operating expenses and related pro forma operating expense adjustments and accepted several of NIPSCO's adjustments, modified a few of NIPSCO's adjustments and proposed additional adjustments. He also sponsored the following adjustments: Billing Determinants – Revenues, Billing Determinants – Fuel Production, Labor Adjustment, Corporate Incentive Plan Expense, Pension Expense, OPEB Expense, medical Benefits Expense, Other Benefits Expense, Other Employee Benefits, Long-Term Incentive Compensation and Profit Sharing ("LTIP") Expense, Benefits Administration Expense, Uncollectible Expense, Vegetation Management Expense, Bad Debts Expense, and Interest Synchronization.

Mr. Eckert stated Mr. Novak's billing determinant adjustment increases the amount of kWh sales for NIPSCO, which in turn increases the total fuel production expense. He calculated the increase to fuel production expense by subtracting NIPSCO's proposed billing kWh billing

determinants from the OUCC's proposed kWh billing determinants and multiplying it by NIPSCO's proposed fuel cost rate resulting in a $1,686,881 increase in fuel production expense.

Mr. Eckert stated Mr. Blakley made recommendations and proposed changes to NIPSCO's ADIT, which he incorporated into the OUCC's revenue requirement calculation.

Mr. Eckert calculated total labor expense as $130,478,191 using NIPSCO's method for calculating labor expense in making his calculation; however he used the actual average headcount for calendar year 2018, which is the same actual average headcount for calendar year 2017, rather than NIPSCO's budgeted headcount for calendar year 2019, resulting in a reduction in labor expense of $6,707,894. He also changed Corporate Incentive Plan, Pension Expense, OPEB, Medical Benefits, Other Benefits, Other Employee Benefits, Long Term Incentive Plan, Benefits Administration Expense, and payroll tax to reflect the reduction to labor expense. Mr. Eckert calculated these adjustments by taking the projected amounts for each of these expenses as reflected in NIPSCO's pro forma number and reduced them by the 4.89% reduction in labor expense, resulting in a combined total downward adjustment of $2,459,206.

Mr. Eckert did not oppose NIPSCO's adjustment to rate case expense, but he recommended NIPSCO reduce base rates for the amortization of rate case expense once the amortization period expires. He supported the continuation of the purchased power over the benchmark calculation.

Mr. Eckert did not oppose NIPSCO's proposal to defer unrecovered ECR expenses and amortize them over two years; however the OUCC recommended that NIPSCO reduce base rates for the amortization of expenses once those amortization periods have expired.

Mr. Eckert did not oppose NIPSCO's proposal that the FAC Rider be modified to reflect the updated cost of fuel that will be established in this base rate case. The OUCC recommended the Commission allow the continuation of the agreement with NIPSCO that allows the OUCC and intervenors to file their testimony and report 35 days after NIPSCO files its petition and testimony.

Mr. Eckert had no concerns with NIPSCO's proposed changes to its RTO Tracker. He stated that since NIPSCO will not know what customers will partake in NIPSCO's requested Rate 831, Tier 2 and 3, until the time of Phase 2 rates, or until and if approved by the Commission, the OUCC does not oppose NIPSCO's proposal to not embed an amount for MISO non-fuel costs and revenues in base rates; however, if Rate 831 is denied by the Commission, and similar to other Indiana investor-owned utilities, there may be a reason to embed an amount of MISO non-fuel costs and revenues in base rates, as there may not be any unknowns and embedding an amount in base rates may reduce the volatility of costs through the rider. The OUCC also did not oppose NIPSCO's proposal to reset OSS margin credit in base rates to zero dollars and track 100% of all OSS margins above zero dollars as a credit to customers through the RTO Rider. The OUCC also did not have any concerns with NIPSCO's proposal to pass back 100% of any demand margins resulting from back-up and maintenance services as a credit to customers through the RTO Rider.

Mr. Eckert testified the OUCC does not oppose NIPSCO's proposal to remove the interruptible credit from the RA Tracker. The OUCC also does not oppose NIPSCO's proposal to remove all embedded costs and/or credits associated with capacity from base rates and track 100% of all capacity costs and/or credits as a charge/credit to customers through the RA Tracker because

such treatment of capacity purchase costs and sales credits: as (1) NIPSCO relies on the MISO PRA to sell excess capacity; (2) NIPSCO does not control the MISO PRA clearing prices associated with capacity; and (3) the auction process can vary.

With regard to the cost allocation factors for NIPSCO's TDSIC, Mr. Eckert recommended that the Commission require that NIPSCO use the customer class revenue allocation factors recommended by Mr. Watkins.

Mr. Eckert testified that the OUCC does not oppose NIPSCO's proposal to treat Indiana URT as a separate line item on customer bills, resulting in removal of URT from all of its riders.

B. Neha Medhekar. Ms. Medhekar testified that NIPSCO's filing includes ratepayer benefits resulting from the TCJA because the TCJA resulted in a federal tax decrease from 35% to 21%, resulting in excess deferred taxes that are being returned to the customer over the remaining life of the assets.

Ms. Medhekar stated NIPSCO's forecasted property tax expenses for 2018 and 2019 are reasonable noting that NIPSCO made an adjustment to remove MVP property taxes. She recommended NIPSCO's proposed payroll tax expense amount should be reduced based on Mr. Eckert's adjustment to O&M labor expense. She testified NIPSCO's calculation of public utility fee is consistent with the Commission's 2018 Annual Report providing the 2018-2019 public utility fee billing rate as 0.001202040.

Ms. Medhekar testified NIPSCO's customers will benefit from removing URT from basic rates, and the OUCC does not object to NIPSCO's proposal. She noted that if not approved, URT would need to be included in total cost related to taxes other than income resulting in an increase in gross retail electric revenue of $32,994,983.

Ms. Medhekar did not oppose NIPSCO's calculated state income tax rate. She explained that any adjustment to income results in an adjustment to income tax expense. As a result of the OUCC's proposed adjustment to NIPSCO's revenue requirement, there is a reduction of $573,729 for state income tax expense and a reduction of $2,021,439 for federal income tax expenses.

Mr. Medhekar has no objection to NIPSCO's calculation of state excess deferred taxes.

C. Wes R. Blakley. Mr. Blakley clarified the actual total company percentage increase in revenue requirement NIPSCO is requesting is 7.77% to arrive at its total company pro forma proposed revenues. He noted that at 1,000 kWh, if NIPSCO's requested increase were approved in its entirety, a typical residential customers would experience an 11.54% rate increase or $15.11 per month increase.

Mr. Blakley calculated NIPSCO's annual accrual depreciation using the 2019 forecasted future accruals in the depreciation study, and applied the results to the composite remaining life of the coal assets from its depreciation study in Cause No. 44688, resulting in an increase to NIPSCO's annual depreciation accruals of approximately $42 million. He stated the accelerated depreciation proposed by NIPSCO provides additional annual cash flow of approximately $42 million that will last through 2030, which is a benefit to NIPSCO, as is the special ratemaking treatment proposed for Schahfer and the ongoing "return on" it seeks to earn on these retired coal

assets. He indicated that any increased rates due to the accelerated retirements should be mitigated. Mr. Blakley proposed a mitigation mechanism in which ratepayers are credited with the effect of the annual depreciation of Schahfer and Michigan City. He explained the credit mechanism would function similarly to a Construction Work in Progress ("CWIP")/Plant Investment tracker, in which plant investment is reduced by associated depreciation over a period, and the return "on" is calculated on the new, lower net plant balance. He explained that while the plant investment is decreasing each year due to depreciation of the investment, NIPSCO would still receive a return "on" the investment with the credit reflecting the difference between the amount authorized in rates and the actual investment amount adjusted for depreciation. He noted that the credit would be repeated annually until the physical asset or regulatory asset is fully depreciated or amortized.

Mr. Blakley disagreed with NIPSCO's proposal to return unprotected excess ADIT over the same period as the protected excess ADIT. He stated that the public interest would not be served by allowing NIPSCO to amortize unprotected excess ADIT over 26 years. He instead proposed NIPSCO amortize unprotected excess ADIT over the expected life of the rates set in this Cause for five years, resulting in an annual amortization of $36,680,662 for unprotected excess ADIT.

D. J. Randall Woolridge. Dr. Woolridge recommended a 9.25% return on common equity, an overall rate of return of 7.41% from investor-supplied capital, and a 6.27% overall fair rate of return from capital. He primarily disagreed with Mr. Rea in measuring NIPSCO's rate of return or cost of capital as follows: (1) significantly different views regarding the state of the markets and the outlook for capital costs; (2) Mr. Rea's DCF equity cost rate estimates are excess because he has (a) asymmetrically eliminated low-end DCF results, (b) relied excessively on the earnings per share growth rates of Wall Street analysists and *Value Line*, made an inappropriate adjustment for leverage, (c) made an inappropriate adjustment for flotation costs, and (d) included the DCF results of a non-utility group of companies; (3) Mr. Rea's CAPM equity cost rates are overstated because he has (a) used economists' forecasts of future interest rates, (b) made a market value – book value leverage adjustment to his betas, (c) employed inflated historical and projected MRPs that do not reflect current market fundaments, (d) included unjustified size and flotation cost adjustments, (e) used the CAPM results of a non-utility group of companies, and (f) employed a variance of the CAPM; (4) Mr. Rea's risk premium approach produces inflated equity cost rates for NIPSCO because he has (a) used economists' forecasts of future interest rates, (b) employed inflated historical and projected risk premiums that do not reflect current market fundamentals, (c) made a market value – book value leverage adjustment to his betas, (d) included an unjustified flotation cost adjustment, and (e) included the risk premium results of a non-regulated group of companies; and (5) Mr. Rea used a non-traditional equity cost rate approach.

E. William H. Novak. Mr. Novak stated the primary differences between NIPSCO's and the OUCC's calculations of forecasted period billing determinants are due to different forecasts for normal weather and customer growth and recommended the appropriate: (1) number of customer bills to set rates upon should be 6,761,663, an increase of 212,483; (2) billing demand should be 14,160,249, a decrease of 20,012; and (3) kWh usage should be 12,101,489,114, an increase of 65,507,561. He explained how his test period billing determinants were adjusted for weather and added customers and explained his analysis for consideration of usage for NIPSCO's industrial customers stating that he adopted NIPSCO's proposed billing determinants and revenues associated with Rates 830 and 831. Mr. Novak stated that he adopted NIPSCO's proposed test

period values for the remaining billing determinants primarily consisting of certain minimum bills related to three-phase charges, horsepower charges, and charges based on residential or commercial pumps as well as the test-period billing determinants for reconnection charges, turn-on charges, returned check charges, and automatic meter opt-out charges, which have remained relatively consistent since 2012. He stated the forward-looking billing determinants were multiplied by the current base tariff rates giving $1,412,394,583 in revenues.

F. Peter M. Boerger. Dr. Boerger testified regarding NIPSCO's proposal for a new rate design (i.e., Rate 831) that would allow certain large industrial customers to pay MISO wholesale market prices for service under Tiers 2 and 3 (non-firm) service under NIPSCO's proposed Rate 831. He indicated that the OUCC expects that access to the wholesale market will allow these customers to lower their cost of electric service compared to NIPSCO's current rates. He highlighted the significance of this issue for regulatory policy across all Indiana electric utilities in that it is a first-of-its-kind request.

Dr. Boerger presented NIPSCO's estimate, obtained through discovery, of a $40.2 million cost shift from industrial customers to other rate classes through the implementation of Rate 831. He referred to OUCC witness Watkins' testimony that this $40.2 million cost shift serves as a minimum value for the cost shift and that the shift may be higher. He explained that this cost shift would allow this class of customers to avoid a significant share of NIPSCO's legacy costs that would otherwise be allocated to these customers under a cost-based rate. He presented the OUCC position that because of this cost shift, NIPSCO's proposal is not reasonable without a payment from Rate 831 customers, which he called a "transition charge" to be recovered over the period through which NIPSCO recovers accelerated depreciation on its coal-fired plants. Under this OUCC proposal, the exact size of the annual transition charge would be determined in the Phase 2 rate proceeding in this Cause, which would also be used to adjudicate the effects of Rate 831 customers not subscribing to the amount of firm service that NIPSCO envisioned in designing Rate 831 charges. The revenues from the transition charge would be allocated to other rate classes based upon the production cost allocation methodology approved in this Cause.

Dr. Boerger also presented concerns about Rate 831 tariff provisions. Specifically, he identified the early termination of Rate 831 contract provisions under Section 5.8 of its proposed tariff, which otherwise requires a five-year contract provision before customer commitments to firm service can be reduced and a five-year notice provision before a customer's firm service can be increased. He stated that these notice provisions are important to the reasonableness of the tariff and should not be allowed to end prematurely. In response to that concern, he presented the OUCC recommendation that Section 5.8 provisions not apply to Rate 831 contracts. Another Rate 831 provision with which Dr. Boerger takes issue pertains to the allowed 12-month notice provision for reducing firm service in the event of "aggregation" or "partially closing a Premise." He finds these provisions to be vague and not reasonably justified and that their inclusion in the Rate 831 tariff provisions is unreasonable.

Dr. Boerger took issue with the design of NIPSCO's proposed transmission charge under Rate 831 and the related Rider 876. He stated that this transmission charge was intended by NIPSCO to recover the Rate 831 share of transmission revenue requirement, and identified that the OUCC does not object to the inclusion of a transmission charge in NIPSCO's tariff. However, he explained that the proposed charge would not adequately recover the cost of providing service

for back-up of self-generation facilities, in that it only charges those facilities for the service of wheeling electricity at the time of unexpected generation outages to the exclusion of the cost of providing service for "standing ready" to move power, which is a 365 day per year service. He explained that the charge as proposed by NIPSCO would under-recover revenue requirement for the back-up transmission service and provide inappropriate economic signals for the building of self-generation facilities. He recommended that NIPSCO's transmission charge be designed to recover transmission revenue requirement on the basis of demand, including the amount of demand needed to back-up self-generation facilities. This approach would require establishing a contract level of back-up service for self-generation facilities, which would be reflected in the potential peak load from Rate 831 customers' non-firm transmission needs. He further recommended that NIPSCO rerun its cost of service and rate design analysis to include such non-firm demand, including back-up of self-generation, which should be presented in the Phase 2 rate proceeding in this Cause. Finally, he recommended that such a transmission charge be included as part of any successor to NIPSCO's 700 series of rates if NIPSCO's Rate 831 proposal is not approved.

G. Glenn A. Watkins. Mr. Watkins testified regarding Cost of Service, which addresses the reasonable allocation of NIPSCO's revenue requirement to the various customer classes. He testified that NIPSCO filed this case in part due to its proposed rate restructuring plan for large industrial customers that would allow these customers to purchase the majority of their energy requirements in the wholesale market and would collectively save on average approximately $47.1 million annually on their total electric bills based on their 2017 and 2018 actual usages and load profiles. As a result of NIPSCO's proposed industrial ratemaking plan, all remaining customers would be responsible for NIPSCO's total investment in generation plant. He stated that even though NIPSCO's generation plant was planned and built in large part to meet the load and energy requirements of large industrial customers, these large customers would be able to walk away from any cost responsibility associated with NIPSCO's legacy fixed generation costs wherein all remaining customers would be responsible for the entire cost of NIPSCO's generation plant. Mr. Watkins estimated the impact on all other customers' rates and revenues of NIPSCO's proposed industrial rate restructuring plan is in the range of $40.2 million to $80.2 million.

Mr. Watkins discussed NIPSCO's rate restructuring plan and how the largest industrial customers would qualify for Rate 831 in which these customers will contract for a specified amount of firm capacity during each hour of the year and any additional load would be purchased at the prevailing day ahead wholesale LMP. NIPSCO projected only a small portion of these large industrial customers' loads will be provided from NIPSCO's own generation resources. The vast majority of these large industrial customers' loads and energy requirements will bypass NIPSCO's generation resources wherein these load and energy requirements will be purchased directly from the wholesale market. Mr. Watkins testified that under NIPSCO's proposed restructuring plan, the majority of large industrial loads will bypass NIPSCO's generation system such that the remaining residential, commercial, municipal, and small industrial customers must then pick up a much larger percentage of NIPSCO's fixed, or sunk, generation plant-related costs. As a result of these large industrials bypassing NIPSCO's generation system, a significant portion of NIPSCO's fixed generation costs would be stranded absent an alternative ratemaking plan. He discussed how he has not been able to quantify the impact on all other customers with any level of precision because NIPSCO has presented its case as if the plan will be accepted by the Commission. He stated that NIPSCO has not presented its evidence based on the actual current rate structure but rather, only after all of the numerous large industrial adjustments are made as proposed under its rate

restructuring plan. Through discovery, Mr. Watkins was able to determine a range for the impact on all other customers in the range of $40.2 million to $80.2 million.

To support his position that Rate 831 would reduce large industrial customers' total electric bills, Mr. Watkins used 2017 and 2018 data from multiple data request responses (total electric bills, total kWh consumption, hourly loads, and hourly MISO day-ahead LMPs), along with each customer's projected contract demands from Dr. Gaske's Attachment 18-H. Mr. Watkins then compared each customer's proposed Rate 831 total electric bill with actual total bills for 2017 and 2018. He concluded Rate 831 customers would have saved $69.5 million during 2017 and $24.8 million during 2018 for a two-year average annual savings of $47.1 million.

Mr. Watkins addressed the allocation of generation and transmission costs to the customer classes. With regard to generation plant, Mr. Watkins testified that utilities design and build generation facilities to meet both the energy (kWh) requirements and the demand (kW) requirements of their customers on a collective basis. He explained because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated. Mr. Watkins discussed how utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity kW and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year, there is an optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Mr. Watkins explained that methods focused solely on seasonal peaks, such as 1CP and 4CP, are inconsistent with the way utilities plan their systems to meet both peak requirements and their customers' energy requirements throughout the year. He stated that NIPSCO's portfolio of generating assets is comprised predominately of large baseload units that serve the energy needs of NIPSCO throughout the entire year. Furthermore, the total dollar amount of generation investment for utilities such as NIPSCO that have coal generation facilities includes a majority of its net investment to comply with environmental or pollution control requirements. These environmental or pollution control investments are related to the burning of fuel, which is energy-related. As a result of the energy/capacity cost trade-off and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes. Mr. Watkins demonstrated that a majority of NIPSCO's generation investment is related to baseload units that serve all customers throughout the year, which the Commission has previously recognized. Mr. Watkins cited to NIPSCO's last litigated rate case (Cause No. 43526), where the Commission found (at p. 85):

> Much of the capital investment costs at issue were, in fact, incurred to meet NIPSCO's energy requirements at lower costs thereby minimizing the total cost of service. This is consistent with the evidence that NIPSCO's system was designed, planned, and built in material part to serve the loads of its energy intensive

industrial customers. Moreover, we note that the most recent capacity addition to the NIPSCO system was the intermediate/baseload combined cycle Sugar Creek facility, and not a "peaker" generating plant.

Mr. Watkins discussed how Dr. Gaske conducted his COSS utilizing the 4CP method to allocate generation costs. Under Dr. Gaske's 4CP method, the entire amount of NIPSCO's generation plant investment is allocated based on four hours of peak demand. Dr. Gaske assumed that the cost per kW is the same for baseload units as for peaker units, and he has also assumed that the utilization of NIPSCO's baseload units are the same as its peaker units; i.e., peaker units are dispatched and run at the same level throughout the year as baseload units. Mr. Watkins testified that Dr. Gaske indicated either the 4CP or 12CP methodology would be appropriate for NIPSCO's production function, but he chose to only use the 4CP allocation method for NIPSCO's fixed production costs in this case. Mr. Watkins testified that the Commission has previously approved the 12CP methodology for NIPSCO and in fact, directed NIPSCO to utilize a 12CP study as the initial basis on which to determine class revenue responsibilities (43526 Final Order, p. 85). Mr. Watkins testified that Dr. Gaske's 4CP COSS results in several classes receiving a free ride and assign no generation cost. Even though these customers require generation service, they are not assigned a single dollar of rate base associated with generation capacity costs.

Mr. Watkins explained that neither NIPSCO nor Dr. Gaske conducted a cost allocation study based on the current configuration of customer classes, the current usage and load profiles of its various customer classes, nor the current revenues associated with NIPSCO's retail customers. Rather, NIPSCO and Dr. Gaske have presented their case under the assumption that the Commission will approve NIPSCO's proposed Rates 830 and 831 restructuring. As such, Dr. Gaske's COSS only reflects NIPSCO's proposal that a significant amount of large industrial load will leave the NIPSCO system for generation purposes. He stated that this has a profound impact on COSS results. Under NIPSCO's proposals and Dr. Gaske's COSS analysis, all other customers are then allocated the full amount of NIPSCO's capacity-related generation costs wherein the large industrial classes' loads are expressed at significantly reduced levels due to Rates 830 and 831. Mr. Watkins explained this choice by NIPSCO as problematic, and due to the massive number of adjustments that are interrelated to NIPSCO's proposed rate restructuring for Rates 830 and 831, he was not able to create or depict NIPSCO's total costs and revenues under the actual current rate configuration and customer profiles. Additionally, Dr. Gaske only utilized the results of his COSS to assign revenue responsibility to, and design rates for, the proposed Rate 831 rate schedule. With regard to all other rate classes, Dr. Gaske assigned any remaining overall increase in the revenue requirement to classes on an equal percentage basis.

Mr. Watkins explained that to show the relative shift in cost responsibility as a result of NIPSCO's proposal to present its case based on the assumption that its Rate 831 restructuring proposal will be accepted, he had to use Dr. Gaske's 4CP COSS from NIPSCO's last rate case. Mr. Watkins then compared Dr. Gaske's 4CP allocators in that case to his 4CP allocators in this case to show the relative shifts in generation costs. NIPSCO's proposed large industrial rate restructuring plan greatly reduces the large industrials' allocation of generation-related costs from 29.80% in the last case to 11.88% in this case. Mr. Watkins explained that Dr. Gaske must then allocate more costs to the remaining classes. For example, the residential class' generation allocation factor increases from 30.28% to 42.07%.

Mr. Watkins conducted three alternative COSS using the Base-Intermediate-Peak ("BIP"), Peak and Average ("P&A"), and 12CP allocation methodologies. He stated that based on NIPCSO's configuration of generation resources and its load profile, the BIP and P&A methods better reflect the capacity/energy tradeoffs that exist within NIPSCO's generation-related costs. Additionally based on the Commission's prior acceptance of the 12CP method to allocate NIPSCO's generation-related costs, he conducted COSS using each of these three allocation methodologies. Mr. Watkins discussed how BIP and P&A methods more closely reflect the manner in which NIPSCO has planned, built, and utilizes its generation resources and more closely correlates to cost causation; however, the 12CP method is not an unreasonable approach that this Commission has used for allocating NIPSCO's generation costs for several rate cases. Mr. Watkins demonstrated the proposed Rate 831 revenue requirement (using NIPSCO's requested increase) under the alternative allocation methods is: (1) 4CP: $149,068,200; (2) BIP: $172,911,300; (3) P&A: $169,096,200; and (4) 12CP: $162,158,600. He concluded that the difference between Rate 831 revenue requirement from Dr. Gaske's 4CP to the more reasonable Commission-approved 12CP methodology allocates $13,090,400 more to large industrial customers.

Mr. Watkins testified that NIPSCO's proposed class revenue distribution is reasonable with one major caveat. He stated that if the Commission adopts NIPSCO's Rate 831 proposal for large industrial customers, NIPSCO's proposal to develop Rate 831 rates based only on his allocated revenue requirement for this class is unfair and unreasonable to all other customer classes. He stated that this is because Dr. Gaske's allocated revenue requirement for Rate 831 is based upon these customers bypassing NIPSCO's generation system for the majority of their load and energy requirements. Under NIPSCO's proposal, all other customers would be responsible for the level of fixed generation investment that large industrial customers would walk away from. To help alleviate this cost shift, he recommended if the Commission authorizes some form of Rate 831, it should use a more appropriate cost allocation method and implement a transition charge.

Mr. Watkins testified that due to the manner in which NIPSCO presented its case, cost responsibility across classes cannot be determined. Based on this, Mr. Watkins agreed the most reasonable method to assign the remaining increase is across classes on an equal percentage basis.

Mr. Watkins discussed how NIPSCO has requested to increase fixed customer charges for residential and small commercial rate classes even though these customer charges were recently increased by a significant percentage in Cause No. 44688. Mr. Watkins conducted a residential direct customer analyses, which showed at most residential direct customer cost is $5.31 per month, and a small commercial direct customer cost is at most $9.15 per month. Mr. Watkins recommended that even though his direct customer cost analyses indicates that significant reductions to current fixed monthly customer charges applicable to residential and small commercial customers are appropriate, in the interest of rate continuity, gradualism, and impacts on individual customer bills that the current monthly customer charge of $14.00 for residential and $24.00 for small commercial (Rates 720, 721, and 722) be maintained.

8. CAC Case-in-Chief.

A. Jonathan Wallach. Mr. Wallach addressed NIPSCO's proposals to: (1) restructure service for large industrial customers; (2) allocate among the various rate classes the

forecasted revenue deficiency for the 2019 test year; and (3) increase the monthly customer charge for residential customers based on the results of NIPSCO's ACOSS.

Mr. Wallach provided an overview of NIPSCO's proposal for a new industrial service structure, described how NIPSCO determined the amount of demand-related embedded production costs to be recovered through the proposed Tier 1 demand charge, and explained how test-year demand-related production costs would be allocated to large industrial customers if industrial service is not restructured. Mr. Wallach stated that NIPSCO has always faced the risk of loss of industrial load – with the associated loss of contribution to NIPSCO's fixed costs – and has attempted to mitigate such risk with special contracts and interruptible rates. However, NIPSCO believes there is now a heightened risk due to changing economic landscape that has reduced the cost to industrial customers of alternatives to NIPSCO firm service. He stated that the proposed restructuring will result in a near-term shifting of some firm costs currently being recovered from the industrial customers to other customers.

Mr. Wallach testified that NIPSCO's Rate 831 proposal would unduly subsidize large industrial customers by shifting recovery of $67-$80 million of embedded production costs to other rate classes by allowing large industrial customers to take fixed rate service at contract demand levels well below total customer demand. He stated NIPSCO proposes to allocate embedded production costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand not contract demand. Consequently, he maintains that the proposed industrial rate structure would recover from large industrial customers less than their fair share of embedded production costs and instead shift recovery of such costs to other rate classes.

Mr. Wallach recommended that Rate 831 revenues be maintained at test-year levels under current rates and that revenues for all other classes be increased by an equal percentage to recover the requested revenue increase. He stated this would thereby reduce the industrial subsidy and provide a fair allocation of the requested revenue increase.

Mr. Wallach provided an overview of NIPSCO's proposal to increase the monthly fixed customer charge for residential customers from $14 to $17 and disagreed with NIPSCO's argument that demand-related costs are fixed for rate-design purposes. He stated that while such costs may appear fixed from a short-run accounting perspective since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load, from the long-run perspective of cost-causation and price efficiency, plant investments are variable with respect to customer usage. He stated that shifting recovery of load-related costs from the volumetric energy rate to the fixed customer charge would drive the energy rate from long-run to short-run marginal costs and thereby dampen price signals for efficient customer behavior.

Mr. Wallach recommended that the Commission approve a residential fixed customer charge at a cost-based rate of $12.55 per residential customer per month.

B. John Howat. Mr. Howat described the need for and recommended that the Commission direct NIPSCO to implement a comprehensive low-income bill payment assistance program that targets current bill benefits to customers eligible to participate in the federal Low-Income Home Energy Assistance Program ("LIHEAP") with an arrearage management design

component. According to Mr. Howat, the estimated cost of the recommended program represents just over $9 million per year—or 0.547% of NIPSCO's revenues from sales to residential, commercial, and industrial customers, which could be collected through a uniform volumetric charge. He also recommended that NIPSCO report data monthly to the Commission and stakeholders regarding general residential and low-income customer accounts, billing, receipts, arrearages, notices of disconnections, bill payment agreements, disconnections of service for nonpayment, reconnections of service after disconnection for non-payment, accounts written off as uncollectible, and accounts sent to collection agencies. Mr. Howat presented evidence to demonstrate that shifting utility cost recovery from the volumetric to fixed monthly customer charge portion of bills disproportionately harms low-volume consumers within a rate class and recommended the Commission reject NIPSCO's proposal to increase the monthly fixed customer charge and instead, lower it to CAC's recommended figure of $12.55.

9. ICC Case-in-Chief.

A. Emily S. Medine. Ms. Medine testified that NIPSCO's proposal to allow its largest industrial customers to opt into retail wheeling and reduce or eliminate paying for generation assets built to serve their firm and interruptible loads should be rejected for the following reasons: (1) it will have significant adverse impacts on NIPSCO's other customers; (2) the proposal was not modeled in NIPSCO's 2018 IRP; (3) NIPSCO has invested heavily in generation assets to serve the firm and interruptible loads of those large industrial customers and to the extent those customers are allocated less of the cost of those assets, NIPSCO will seek to recover those stranded costs from other customers; and (4) NIPSCO's proposal for retail wheeling for large industrials customers raises statewide policy issues that are inappropriate for resolution in a rate case. She recommended that NIPSCO's request to allow its largest industrial customers to opt for retail wheeling should be denied without prejudice so that: (1) NIPSCO can perform truly integrated resource planning in its next IRP and include the migration of large industrial firm and interruptible load to retail wheeling; (2) the Commission can include in its Statewide Analysis and annual reporting to the legislature the issues surrounding potential migration of load to market resources in lieu of local utility resources; (3) the issue of stranded cost allocation can be considered from a policy perspective on a statewide basis.

Ms. Medine concluded that NIPSCO's proposed acceleration of depreciation for coal generation units and proposed accounting authority to defer remaining net book value of coal generation assets as regulatory assets after early retirement should be rejected for the following reasons: (1) these proposals are premature because they rely upon an IRP that is still under review and comment; (2) NIPSCO's 2018 IRP modeling suffers from the same fatal flaw as its 2016 modeling – NIPSCO's resource planning is not integrated because it separates (a) the modeling of retirement decisions (using hardwired retirement dates selected by NIPSCO rather than optimized by the model), from (b) replacement portfolio decisions; (3) NIPSCO did not adequately address customer rate impacts that will result from the premature retirements of its remaining coal fleet, accelerated depreciation of the remaining costs and the creation of a regulatory asset; and (4) NIPSCO expended no effort in seeking to minimize the costs of the early retirement of the Schahfer units, including but not limited to, actively marketing the units for sale to third parties. She recommended that in connection with doing a truly integrated resource plan in its next IRP, NIPSCO should, as part of its retirement planning, solicit and meaningfully consider offers from third parties to purchase those assets in order to properly assess the costs of retirement. NIPSCO

should not reject without due economic analysis purchase offers that may include proposals for NIPSCO to purchase capacity or energy from those units.

Ms. Medine concluded that if NIPSCO's ECRM Tracker is discontinued, NIPSCO should be prohibited from including such variable operating costs associated with said environmental projects in the calculation of its offer prices when bidding its units into the MISO market.

10. ICC / ICARE Case-in-Chief.

A. Charles S. Griffey. Mr. Griffey testified regarding NIPSCO's 2018 IRP. He stated that the IRP fails to demonstrate that NIPSCO's planned retirements of Schahfer and Bailly are reasonable because NIPSCO created an IRP process using flawed methodology and assumptions, which lead to the conclusion that the coal plants should be retired in the years NIPSCO predetermined.

Mr. Griffey testified against NIPSCO's requests to accelerate depreciation and create a regulatory asset upon retirement of each coal unit. He indicated it is premature for the Commission to determine whether NIPSCO should receive a return on the regulatory asset if it is approved, or what the level of return should be. He testified he takes no position on whether the new market structure and associated cost shift is in the public interest, but he noted that there is no tie between the proposed new structure and the results of the IRP. He stated that because the IRP analysis is significantly flawed, the Commission should postpone any determination regarding rate recovery for the associated plant retirement decisions until after NIPSCO's next IRP.

11. IMUG Case-in-Chief.

A. Theodore Sommer. Mr. Sommer addressed opportunities to collaboratively launch a Municipal Solar Program ("MSP") that would benefit municipalities, their residents, residents in NIPSCO's service area, and NIPSCO and would foster new employment opportunities. He stated the MSP would be designed to maximize benefits for northern Indiana utility regulatory stakeholders. He noted that solar panels could be placed on vacant municipal land, vacant municipal rooftops, blighted land, and brownfields. He explained that participating municipalities would select the available qualifying sites for possible installation of solar panels based upon total value and would have the opportunity to offer solar sites for consideration with NIPSCO. He stated that funding for the MSP panels and installation would be obtained from NIPSCO, a private lender, a private partner, or the municipalities themselves. He indicated there currently is a 30% ITC on the purchase of solar panels suggesting that private financing may be a viable path to capitalization. Mr. Sommer detailed MSP benefits including: (1) new employment opportunities; (2) job training opportunities; (3) Hoosier Homegrown Energy Economic Stimulus; (4) lower purchased power costs for participating municipalities; (5) enhancing public convenience and necessity; (6) environmental benefits and public awareness; and (7) consistency with and promotion of NIPSCO's customer efforts and vision. He testified IMUG is willing to collaboratively work with NIPSCO and others to detail the proposed MSP.

Mr. Sommer had concerns with NIPSCO's proposed streetlight rates with increases of approximately 33% to 49% reflecting NIPSCO's proposed termination of the 50% TDSIC socialization of capital conversion costs for NIPSCO-owned streetlights that have already been

converted to LED. He said that ending the 50% LED retrofit socialization created in the approved seven-year TDSIC plan at this time would result in a shocking LED rate increase to IMUG members. He stated that NIPSCO intends to roll the TDSIC LED street light rate base tracker impacts into rate base as of December 31, 2019. He explained that any streetlight fixtures changed out after the time of that cutoff will be afforded a discounted rate similar to the rate those will have previously experienced. He stated that IMUG municipalities first suggested the LED conversion program, worked to maximize the technical characteristics and economic value of the LED conversion program, and worked to have the LED program approved. However, those municipalities who first converted to LEDs would only receive seven-year TDSIC plan 50% savings for a brief two years and would suffer huge rate increases while those who did not invest the time, effort, and money in the LED program will be converted to LED in the future and will continue to receive the TDSIC socialization or discounted rate on LED converted streetlights for a much longer time period. Mr. Sommer proposed that those with the discounted rate for LED rates continue to be charged the discounted rate following December 31, 2019.

Mr. Sommer proposed that 50% socialization of the converted LED streetlight rate responsibility be allocated to the other customer classes because all people in NIPSCO's service area who travel the roads and sidewalks after dark are the primary beneficiaries of streetlights.

12. Industrial Group Case-in-Chief.

A. Michael P. Gorman. Mr. Gorman testified regarding a number of specific adjustments to NIPSCO's claimed revenue deficiency and supported his recommended return on equity ("ROE") of 9.35%, the midpoint of his recommended range of 9.0%-9.7%.

Mr. Gorman first addressed NIPSCO's proposed treatment of unprotected excess ADIT. He noted that NIPSCO had adjusted its cost of service to reflect the new 21% corporate tax rate implemented by the TCJA and that NIPSCO was proposing to return protected excess ADIT using the average rate assumption method ("ARAM") consistent with IRS normalization rules. Mr. Gorman noted that NIPSCO also proposed using approximately a 15-year ARAM amortization period to return unprotected excess ADIT but a ten-year amortization period for other assets. He recommended using a ten-year amortization period for unprotected excess ADIT. Mr. Gorman explained why he considered NIPSCO's decision to use the ARAM amortization period for unprotected excess ADIT unreasonable and why use of a ten-year amortization period was more appropriate. Based on his recommendation, Mr. Gorman reduced NIPSCO's claimed revenue deficiency by approximately $5.15 million.

Mr. Gorman next recommended reducing NIPSCO's revenue deficiency by approximately $3.32 million to reflect a downward adjustment to its labor expense. He made this adjustment by removing costs associated with unfilled positions from NIPSCO's budgeted headcount.

Mr. Gorman also proposed an adjustment to NIPSCO's proposal to recover a regulatory asset related to the deferral of unrecovered ECR expenses incurred prior to the expected implementation date of new rates. He did not oppose NIPSCO's calculation of the value of the deferred asset at approximately $19.0 million; however, he did oppose NIPSCO's proposal to amortize the expense over a two-year period. Instead, Mr. Gorman proposed to match the

amortization period with the expected life of the rates set in this case, which reduced the annual amortization expense by approximately $4.75 million.

Mr. Gorman proposed removal of contingency costs from NIPSCO's demolition cost estimates for four of its generation stations. Mr. Gorman explained how the inclusion of contingency costs were inappropriate and inflated the demolition cost estimates which, in turn, increased the depreciation rates. Mr. Gorman, therefore, proposed adjusting the depreciation rates on certain accounts, which resulted in a reduction of $2.5 million in depreciation expense. Offsetting this decrease by an increase in operating income and income taxes, Mr. Gorman proposed a net reduction of approximately $2.3 million to NIPSCO's revenue requirement.

Mr. Gorman testified regarding NIPSCO's proposed rate of return and requested ROE. Mr. Gorman began his analysis with a review of general market conditions. He then presented evidence related to the authorized ROEs for electric and gas utilities, the ability of utilities to maintain credit ratings during periods of declining ROEs, and their ability to access external capital to support infrastructure investment under reasonable terms. Mr. Gorman also testified regarding the market's assessment of the investment risk of NIPSCO and its parent company, NiSource.

Mr. Gorman described NIPSCO's proposed capital structure, which reflected approximately 43%:57% debt to equity ratio. He stated this was unreasonable for purposes of setting rates for several reasons. He further testified that using a 50%:50% ratio would, without other adjustments, reduce NIPSCO's requested revenue requirement by approximately $23.4 million. Mr. Gorman noted that a similar reduction would be achieved by reducing the requested ROE from 10.8% to 9.90%.

Mr. Gorman then testified regarding his recommendation for NIPSCO's cost of common equity in light of the Hope and Bluefield standard. He explained the methods used to estimate NIPSCO's cost of common equity, including several variations on the DCF model, the Risk Premium Model, and the CAPM and the inputs he used in applying those models. Based on his analyses, Mr. Gorman recommended a range of 9.0% to 9.7% for NIPSCO's ROE, and he recommended return on common equity of 9.35%. Mr. Gorman testified the 9.35% ROE would support an investment-grade bond rating for NIPSCO.

Finally, Mr. Gorman testified regarding his disagreements with Mr. Rea's approach to calculating NIPSCO's ROE, including the use of a flotation cost adjustment, some of the methods used by Mr. Rea, and various inputs used in conducting his analyses.

B. Nicholas Phillips, Jr. Mr. Phillips agreed with NIPSCO's proposal to use a 4CP method for the allocation of generation investment and 12CP for the allocation of transmission investment in its filed COSS. Mr. Phillips testified that NIPSCO's proposed cost of service method is appropriate and produces fair and reasonable results. He said NIPSCO's COSS is consistent with the cost of service method presented by NIPSCO in its last base rate proceeding. He analyzed NIPSCO's historic monthly peaks in the summer period. He stated the 4CP method properly reflects NIPSCO's historic peaks as well as the forecasts used by NIPSCO for capacity planning. Mr. Phillips also testified that NIPSCO's proposed mitigation plan, which basically sets large industrial loads subject to global competition at cost and increases rates for all other classes

on an "across-the-board" basis, maintaining the current subsidy received by residential customers, has merit, given the circumstances in this case.

Mr. Phillips described NIPSCO's plan to establish Rate 831 for its largest industrial customers as a well thought out solution for the retention of the global manufacturing operations of its largest customers and mitigates NIPSCO's risk of investing in significant amounts of capacity and energy associated with the replacement of its aging generating fleet. He stated that the proposed Rate 831 is a logical extension of the interruptible service option implemented and expanded by the Commission in NIPSCO's last two rate case orders. He added the Rate 831 approach will help retain the large industrial customers, including jobs and tax base, while shielding NIPSCO and its other customers of the obligation to provide firm service to a significant amount of load associated with the Rate 831 customers. He added that NIPSCO's COSS incorporates its proposed rate structure and correctly eliminates the loads for which it will no longer be required to provide generating service.

Mr. Phillips also testified that NIPSCO's proposal to combine the current low load factor Rate 732 and current high load factor Rate 733 into a new Rate 830 for smaller industrial customers results in apparent unintended increases for some customers. Consequently, he recommended the retention of both a low load factor rate and high load factor rate for those current customers receiving service on Rate 732 and Rate 733 that are not opting, or are not eligible, for Rate 831 service. He noted NIPSCO has offered a low load factor rate and a high load factor rate to its customers for decades and those offerings should not be discontinued. Mr. Phillips also recommended that NIPSCO implement a voltage adjusted fuel factor to more accurately reflect the cost to serve customers at varying voltage levels.

C. James R. Dauphinais. Mr. Dauphinais testified in support of the proposed Rate 831 rate structure. He supported NIPSCO's decision as a prudent judgment in light of the risk that large industrial load will continue to leave the NIPSCO system through self-generation, closures, or shifting production to other locations. He stated NIPSCO's largest customers use energy-intensive processes and are subject to intense competition, and Rate 831 would allow those customers greater ability to manage power costs and risks. He described Rate 831 as a logical evolution of existing options. He also stated that Rate 831 would be beneficial to other rate classes by addressing the risk of continued reductions in large industrial load, while better allowing NIPSCO to "right size" its generation resources and avoid excess capacity.

Mr. Dauphinais explained the structure of Rate 831 and the distinct features of Tiers 1, 2, and 3 as well as Rider 876. He proposed an amendment to tariff language to address a proposed MISO change, and a revision to the proposed definition of an industrial "Premise" in light of a then-pending dispute with a large customer.

13. NLMK Case-in-Chief.

A. James A. Lahtinen. Mr. Lahtinen testified in support of the proposed new industrial rate structure. Mr. Lahtinen explained that NIPSCO correctly discerned that basic changes in energy market place fundamentals including that sustainable supplies of domestically sourced natural gas have enhanced the attractiveness of self-supply alternatives for NIPSCO's largest industrial customers. Given NIPSCO's dependence on industrial customers and energy

intensive, competitively at-risk manufacturing facilities for a very large component of its retail electric sales, NIPSCO was compelled to respond constructively to the potential loss of industrial load to on-site generation bypass or production relocation. Based on his previous experience with industrial load loss in Pennsylvania in the 1980s, Mr. Lahtinen commended NIPSCO for proactively developing constructive solutions to retain its largest industrial loads.

Mr. Lahtinen explained that under Rate 831, it was essential that the firm, Tier 1 rates be reasonable for the rate structure to be feasible. He emphasized that the proposed Tier 1 demand charges will be significantly higher than current rates, especially for customers served on current Rate 732, and that it was imperative that Rate 831 rates be designed to provide a rate of return that did not exceed the system average return. Mr. Lahtinen found that NIPSCO's proposed use of a 4CP allocation method for its production plant was reasonable and consistent with cost causation principles given the strong summer peaking nature of NIPSCO's system. Mr. Lahtinen acknowledged that there was substantial uncertainty regarding the amount of Rate 831 load that would be enrolled as firm, Tier 1 service for the first five-year contract term, and that a shortfall in Tier 1 enrollment could have material rate consequences for other customers. Mr. Lahtinen recommended that this uncertainty be resolved in part by increasing the required minimum level of Tier 1 service to the lesser of a customer's historic level of firm service or 30,000 kW.

Noting that under prevailing Rider 775, existing interruptible industrial loads that elect to "buy-through" economic interruptions are charged spot wholesale energy prices, Mr. Lahtinen concluded that the proposal in Rate 831 to expand that buy-through concept to all large industrial non-firm load, which would remain LMRs, was a reasonable approach. He further concluded that the mechanisms that NIPSCO proposed for Tiers 2 and 3 of Rate 831 non-firm service provided the tools reasonably necessary for Rate 831 customers to manage their energy price risk exposure.

Mr. Lahtinen concluded that NIPSCO's proposal to set the Rate 831 revenue requirement based on the cost of service while applying an across the board equal percentage increase to all other rate classes was a balanced and thoughtful approach for re-aligning industrial rates at cost while mitigating the rate impacts on other customers, particularly the residential class. If the Commission determined not to adopt the proposed industrial rate structure, Mr. Lahtinen maintained that the existing industrial rate structure and interruptible Rider 775 should be retained.

14. Peabody Case-in-Chief.

A. Michael J. Nasi. Mr. Nasi testified that NIPSCO's assumed regulatory timelines for compliance with the EPA's CCR Rule and the ELG Rule were too short because of available extension options and EPA's plans to reform both rules. He stated that NIPSCO's estimated capital expenditure and O&M costs were either not backed up by specifics or simply too high. This includes costs for compliance with the CCR Rule, ELG Rule, the CSAPR, and the MATS Rule. He also challenged NIPSCO's retirement decisions based on: (1) inclusion and accuracy of capital and O&M costs for continuing operations and compliance with environmental regulations to justify retirement decisions; and (2) NIPSCO's assumption that both ELG and CCR costs will be incurred regardless of whether the units continue to operate.

Regarding the ELG Rule, Mr. Nasi stated that NIPSCO overestimated the cost of compliance based on the current postponement of certain compliance dates and EPA's intent to

revise the ELG Rule by December 2019. He further claimed there were "discrepancies" in NIPSCO's cost estimates and "uncertainties" in the status of the ELG Rule that suggest NIPSCO's request to be unreasonable and imprudent. He stated that there was an unexplained mismatch between certain ELG compliance costs and that NIPSCO should have advocated for broader ELG Rule changes because further ELG Rule changes could potentially be taken up by EPA.

Regarding the CCR Rule, Mr. Nasi testified that NIPSCO overestimated compliance costs, which are estimated to be $226 million, as provided in discovery by NIPSCO. After discussing the background and status of the CCR Rule, including a recent court decision, he opined that he did not agree that NIPSCO's estimated CCR costs within its IRP are reasonable and prudent. He also discussed the AROs and asserted this information was included in Mr. Carmichael's testimony to establish additional justification for NIPSCO's proposed retirement decisions.

As related to MATS Rule compliance, Mr. Nasi stated that it is inappropriate for NIPSCO to continue assuming it will incur long-term MATS O&M costs for its generating units because there is a significant likelihood that EPA will withdraw MATS entirely or drastically alter the rule thereby reducing the ongoing O&M cost burden. He testified that incorporation of "high O&M costs into [NIPSCO's 2018] IRP" is unreasonable because the EPA announced reconsideration of the MATS rule in August 2018 and proposed a revised supplemental cost finding in December.

Mr. Nasi also raised criticism of NIPSCO's proposed compliance path for CSAPR. His primary criticism was that NIPSCO failed to provide adequate justification for selecting SCR technology over the less costly, alternative selective non-catalytic reduction ("SNCR") technology. He stated that there is no reasonable set of assumptions that could justify NIPSCO's assumed SCR expenditure. He also took issue with the responses NIPSCO provided to Peabody Requests 1-010 and 1-011 (included as Attachment Nos. MJN-5 and MJN-6), wherein NIPSCO explained why it had assumed SCR technology for compliance with CSAPR.

15. Sierra Club Case-in-Chief.

A. Avi Allison. Mr. Allison's primary findings can be summarized as follows: (1) NIPSCO's proposal to increase the residential customer charge is based on a flawed theoretical construct that, if following to its logical conclusion, would ultimately result in a residential customer charger greater than $100 per month; (2) NIPSCO's residential customer charge proposal is inconsistent with sound ratemaking principles and would negatively impact energy conservation efforts and low-income customers and that a reasonable residential customer charge would be lower, not higher, than the current NIPSCO customer charge; (3) NIPSCO has failed to provide sufficient justification for its proposed new industrial service structure that would shift at least $40 million in annual costs from industrial customers to other customer classes; (4) the proposed industrial service structure change is not aligned with NIPSCO's IRP load assumptions; and (5) NIPSCO's proposal to depreciate its remaining coal plants through 2030 strikes a reasonable balance between aligning asset recovery with asset life and minimizing near-term rate shock.

Mr. Allison recommended: (1) the Commission should reject NIPSCO's proposed increase in the residential customer charge and instead lower the residential customer charge to no greater than $12.77 per month and reject the use of a "straight-fixed variable" ("SFV") rate design as a reasonable basis for determining an appropriate residential customer charge; (2) the Commission

should reject the proposed allocation of costs under the new industrial service structure and that given the massive rate impacts on other customer classes, the Commission should not approve the proposal without concrete evidence of substantial, imminent defections by industrial load; (3) if the Commission approves of the general framework of the new service structure, it should still require that NIPSCO allocate a larger portion of its historical fixed costs to industrial customers, as those costs were incurred to serve industrial customers' historical load; (4) if the Commission approves the proposed industrial service structure change, it should require that all future NIPSCO IRP load forecasts account for any reductions in the reduced industrial demand associated with the new service structure; and (5) the Commission should approve NIPSCO's plan to recover the remaining depreciation expenses associated with Schahfer and Michigan City through 2030; however, this approval should not imply pre-approval of specific investments at those plants and should be contingent on NIPSCO following through with its planned coal plant retirement dates.

16. Walmart Case-in-Chief.

A. Steve W. Chriss. Mr. Chriss testified on cost of service issues, revenue allocation, and rate design, including NIPSCO's proposed Rate 831 structure. Specifically, Mr. Chriss advocated that rates be set based on the utility's cost of service for each rate class and that regulatory policies should be set that support the fair-cost-apportionment objective of rate-making, ensuring that rates reflect cost causation. As Mr. Chriss noted, this sends proper price signals to customers and minimizes price distortions.

Mr. Chriss discussed Walmart's concerns with discrepancies in NIPSCO's COSS that impacted the accuracy of assigning overall costs to the customer classes and establishing the cost-basis for the proposed rates, particularly for NIPSCO's Off-Peak Service class on Rate 726, when evaluated in comparison with NIPSCO's COSS filed in the last base rate case. These discrepancies indicated errors with the load characteristics and billing determinants for the Off-Peak Service class. Mr. Chriss explained these errors produced a misinformed revenue allocation in NIPSCO's COSS that understated revenues associated with the Off-Peak Service class and misrepresented the class's contribution to its cost to serve, as depicted by the Index Rate of Return. However, he stated these errors also impacted NIPSCO's representation of the system's overall "subsidy" position between the various classes. Mr. Chriss further noted that the errors contained in the COSS impact the proper rate design for the Off-Peak Service class by producing overstated prices, which would then lead to excess revenues being collected from the class. As such, Mr. Chriss recommended that the Commission reject NIPSCO's COSS because it would lead to rates that are not just and reasonable and would impact the Commission's assessment of the interests of all NIPSCO customers when reviewing the Rate 831 structure proposed for the industrial class.

Mr. Chriss provided his assessment of NIPSCO's proposed allocation of revenues. He stated that by designing Rate 831 at cost and then assigning an equal percentage increase to all other classes, rates were produced that moved all classes further from their actual cost to serve, which is counter to the goal of eliminating or establishing a targeted reduction of subsidies for all classes. As such, Mr. Chriss recommended that the Commission reject NIPSCO's proposed revenue allocation and instead allocate the authorized revenue in a manner that targets and reduces the subsidy burden for all subsidizing classes. Mr. Chriss noted that this could be done by ordering an increase to subsidizing classes that is lower than the system average increase coupled with an

increase to subsidized classes that is above the system average without causing an unduly burdensome rate increase on any class.

Regarding the Rate 831 proposal, Mr. Chriss noted Walmart's concerns that the proposed alternative regulation for this limited class of industrial customers would result in: (1) an unjust shift in cost responsibility from NIPSCO's largest industrial customers to the remaining customers by assigning capacity obligations that are not related to non-Rate 831 customers' actual capacity requirements; (2) the establishment of customer access to the wholesale market, which fails to properly assign transition costs to the departing load; and (3) eligibility requirements that appear to be unduly discriminatory insofar as they exclude other large, sophisticated customers that might also benefit from market access rates. Mr. Chriss recommended that the Commission reject the Rate 831 proposal. However, if the Commission determines that the threat of reduced industrial load warrants immediate action, Mr. Chriss recommended that the Commission establish a solution that addresses the immediate concerns while also addressing the proposed burden on the remaining customers. Mr. Chriss cited to a California state law that requires customers who take service through third-party energy providers to pay a power charge indifference adjustment or an exit fee to ensure that remaining customers are not left with the responsibility to pay transition costs that should be the responsibility of the departing customers.

On July 17, 2019, as requested by the Commission in its July 16, 2019 Docket Entry, Mr. Chriss updated Exhibit SWC-3, an attachment to his prefiled direct testimony. As updated, Exhibit SWC-3 (REVISED) contains a listing and various averages of authorized ROEs in electric utility rate cases ranging from 2016 through July 10, 2019. In particular, the document indicates that the average ROE for vertically integrated electric utilities for the entire period is 9.73% and the average ROE for vertically integrated electric utilities solely for 2019 is also 9.73%.

17. <u>US Steel Case-in-Chief</u>.

A. <u>Brown D. Thornton</u>. Mr. Thornton testified on behalf of US Steel's support of the Rate 831 structure. He identified several aspects of the Rate 831 structure that need to be clarified or resolved prior to its implementation. First, Mr. Thornton recommended that Rate 831 have a phase-in period for customers between the final order in this Cause and May 31, 2020, to coincide with MISO's planning year. Second, he testified that Rate 831 customers should only be financially obligated to either NIPSCO or a third party for the same energy and capacity. Third, Mr. Thornton stated that the Rate 831 tariff should better define NIPSCO's role in the event a Rate 831 customer disputes any MISO charge. Fourth, Mr. Thornton recommended that between the final order and May 31, 2020, NIPSCO and the Rate 831 customers develop a model third-party agreement to govern when a Rate 831 customer remains a retail customer of NIPSCO while contracting for part of its power supply with a third party. Finally, Mr. Thornton recommended that the Rate 831 tariff allow capacity purchases outside of MISO Zone 6 so long as firm capacity is deliverable into Zone 6 to meet MISO's Module E requirements. Ultimately, Mr. Thornton recommended approval of Rate 831 because it provides long-term benefits to NIPSCO's customers by reducing risks for NIPSCO and its customers and ensuring that NIPSCO's largest customers continue to contribute to NIPSCO's fixed costs.

B. <u>Tony M. Georgis</u>. Mr. Georgis testified that US Steel operates three large steel manufacturing and finishing plants in NIPSCO's territory. US Steel is estimated to have a

$55.9 billion total impact on the Indiana economy and is one of NIPSCO's largest customers. Mr. Georgis explained that US Steel is very sensitive to NIPSCO's power prices due largely to international price competition for steel. He testified that in the absence of Rate 831, US Steel may explore other power supply options to significantly reduce US Steel's reliance on NIPSCO through self-built cogeneration that US Steel could certify to FERC as a QF. Mr. Georgis stated that if US Steel leaves the NIPSCO system entirely, the remaining NIPSCO customers would pay the fixed costs currently paid by US Steel, which he estimated at between $17 to $20 million annually, which include labor, depreciation, and other capital costs that do not vary with energy sales.

Mr. Georgis testified that Rate 831 is a natural evolution from NIPSCO's current interruptible service offerings. He recommended that the Commission approve Rate 831 and noted that it benefits other customer classes by simultaneously addressing the needs of NIPSCO's largest industrial customers while ensuring that NIPSCO's remaining customers will not be responsible for replacement generation costs to serve industrial load that is more volatile and able to leave the system with stranded cost. Mr. Georgis recommended adjustments to NIPSCO's over-allocation of transmission costs to the 831 rate class and recommended that NIPSCO subfunctionalize transmission rates for 831 customers to accurately reflect the service voltage levels at which 831 customers receive service. Mr. Georgis also recommended that NIPSCO clarify the firm demand rate calculation and true-up process to be used to ensure that the Rate 831 customers' Tier 1 firm capacity elections meet or exceed the 184,556 kW that NIPSCO proposed to allocate to Tier 1.

18. Cross-Answering Testimony.

A. CAC. Dr. Stanton recommended that the Commission not credit the critiques of NIPSCO's 2018 IRP advanced by ICC witness Medine, ICARE witness Griffey, and Peabody witness Nasi. She found that NIPSCO made significant improvements between its 2016 and 2018 IRPs by conducting an all-source RFP reviewed and improved upon by stakeholders, increasing transparency of modeling data and commodity price forecasts, removing arbitrary limits and unsupported cost additions on renewable resource choices, and addressing other criticisms of its 2016 IRP.

Dr. Stanton stated that although NIPSCO should have modeled a specific representation of Rate 831 industrial load reduction in the IRP as Ms. Medine stressed, the IRP results demonstrate that this modeling very likely would not have changed the order of preference of NIPSCO's portfolios. If anything, an industrial load reduction would have favored earlier retirement of all NIPSCO's coal units (Retirement Portfolio 8) even more strongly. Dr. Stanton explained that Ms. Medine failed to explain or quantify her implied suggestion that NIPSCO should take measures to improve forced outage rates and lower O&M costs at NIPSCO's coal plants or otherwise justify continued use of these coal units. Dr. Stanton also stated that Ms. Medine highlighted the alternative scenarios produced at ICC's request, which included several assumptions favoring delayed coal unit retirements. However, these alternative scenarios were still more expensive than Portfolio 6 and Portfolio 8 and therefore, support NIPSCO's decision to retire all of these units.

Dr. Stanton testified that Mr. Griffey's claims of a solar capital cost bias very likely would not have changed the rank of the eight portfolios by cost or changed the IRP modeling conclusion to retire all coal units. She stated that Mr. Griffey claimed that NIPSCO should have included projected degradation of wind generation into the model. This projected degradation would only

affect wind resources owned by NIPSCO, not resources where NIPSCO has a PPA with the resource owner, who has the onus to maintain the facility. She explained that projected degradation is irrelevant in this case because NIPSCO has or will have a PPA for most of the wind resources currently owned by NIPSCO and offered in response to NIPSCO's RFP.

Dr. Stanton stated that Mr. Griffey argued that NIPSCO should have conducted retirement optimization modeling with NIPSCO's actual replacement portfolios. However, she explained that this very likely would not have changed the selection of Retirement Portfolio 6 as the preferred retirement portfolio. She also stated that Mr. Griffey incorrectly contrasted intermittent renewable generation with dispatchable resources in MISO. She then addressed Mr. Griffey claim that Indiana's wind effective load carrying capability ("ELCC") is lower than other states. NIPSCO's current wind generation does not originate in Indiana, and given the wind bids from multiple states responding to NIPSCO's 2018 RFP, NIPSCO's wind additions cannot be assumed to come entirely from Indiana. She explained that NIPSCO's use of the MISO average ELCC in its modeling, rather than the Indiana wind ELCC, was reasonable.

Finally, Dr. Stanton stated that Mr. Nasi provided no reason for NIPSCO to assume that the MATS rule would be delayed or discontinued.

B. ICC. Mr. Graeter responded to Sierra Club witness Allison's agreement with NIPSCO's underlying decision to accelerate the retirement of Michigan City and Schahfer due to the likely savings shown in NIPSCO's IRP retirement analysis because the calculation of savings Mr. Allison references does not take into account the cost of lost jobs that accelerated retirements could cause. Mr. Graeter performed a Job Impact Study of the Accelerated Retirements of NIPSCO's R.M. Schahfer and Michigan City Power Plants showing that the accelerated retirements will have serious negative impacts on the local communities, while NIPSCO's plan to replace these power plants will do little to soften these impacts.

C. ICARE. Mr. Griffey disagreed with Sierra Club witness Allison's conclusion that any potential loss of industrial firm load (due to the proposed industrial service structure or other causes) would likely render NIPSCO's coal units even less viable than they were found to be in the IRP retirement analysis because maintaining flexibility about when to retire the coal plants and deferring burdensome new PPAs or renewables ownership is likely to have great value. He also disagreed with Mr. Allison's agreement with NIPSCO that retiring Schahfer in 2023 and Michigan City in 2028 will likely save NIPSCO's customers more than $4 billion in NPV terms relative to continuing to operate the units because the savings are illusory as NIPSCO only made assumptions and ran the Aurora model for 20 years, yet made 30-year NPV calculations.

Mr. Griffey concluded that if his critique of wind resources is proven correct as to such items as unforced capacity ("UCAP") and congestion costs, it means that NIPSCO's failure to accurately model wind resources in its IRP renders the IRP results useless for decision making.

D. Industrial Group. Mr. Dauphinais disagreed with testimony suggesting that Rate 831 inappropriately shifted costs to other customers and with the proposal for transition charges or exit fees for Rate 831 customers. He stated that Rate 831 is a cost-based rate, and the costs incurred by NIPSCO to provide that service are less only because less system resources are being used. He indicated the proposed transition charges would force Rate 831 customers to cover

costs for system resources no longer being used to provide them with service, while also leaving them with cost responsibility for market resources actually used to meet their power needs and the associated market risk.

Mr. Dauphinais disputed the computation of $40.2 million in shifted costs from Rate 831 customers to other customers. He stated that figure does not account for additional OSS margins that NIPSCO will earn and pass through to customers as a result of not serving Tiers 2 and 3 load at average fuel cost, which he calculated as $9.9 million annually. He identified further reductions in price volatility to other customers. He emphasized that, without Rate 831, NIPSCO is at great risk of losing large industrial load due to self-generation, shutdown of facilities, or reduced production. Consequently, lost revenue from those customers could greatly exceed the computation of shifted costs.

Mr. Dauphinais testified the proposed transition charges or exit fees were inappropriate. He stated such charges have not been imposed on customers exercising their right to self-generate or shut down facilities, and it would be misguided to apply such charges here to customers that use self-generation, may use self-generation, or reduce production but for Rate 831. Describing Rate 831 as an initiative to retain at-risk load, he stated the proposed transition charges would undermine that objective and exacerbate the risk. He cited a FERC regulation that permitted recovery of stranded costs only where there was "a reasonable expectation that the utility would continue to serve the customer," an essential predicate absent here. He stated Rate 831 is not retail wheeling, differs in multiple respects from an open access structure, and is supported by the provisions and legislative policy of the Alternative Utility Regulation Act ("ARP Statute"), Ind. Code ch. 8-1-2.5.

Mr. Dauphinais disagreed with the suggestion that NIPSCO's proposed transmission charge should be revised in connection with backing up the self-generation facilities of Rate 831 customers. He stated the transmission rate for back-up service as proposed by NIPSCO was consistent with cost-causation, traditional cost allocation, FERC and Commission rules, and NIPSCO's existing back-up rate. The suggested increase through added demand charges would erect barriers to highly efficient self-generation, contrary to Indiana and Federal policy. He noted NIPSCO allocated transmission costs based on monthly coincident peak demand, not energy, and therefore use of an energy charge will affect only collections from individual customers within the Rate 831 class, with no impact on other classes. He further stated that NIPSCO's allocation of transmission costs is consistent with MISO's current and expected future practices. He cited FERC and Commission rules providing that back-up rates should not be based on an assumption that outages for self-generation facilities on a utility's system will all occur simultaneously, or at system peak, or both, and the addition of demand charges would be inconsistent with those rules.

Mr. Dauphinais also took issue with a proposal that Rate 831 contracts should be exempt from NIPSCO's general rule terminating contracts in the event of a rate case, stating it would be unreasonable to bind a customer to a contract even if a rate case changes the terms and conditions of Rate 831. He further addressed a challenge to a provision in Rate 831 allowing for a reduction in firm demand for closure or partial closure of a customer facility, stating it would be unreasonable to require continued contractual service at the same level when the load being served has significantly changed. Finally, Mr. Dauphinais responded to alternative approaches suggested in the event that actual subscriptions for Tier 1 service end up falling significantly below the

projections assumed by NIPSCO, stating the better alternative would be to establish a process to determine Tier 1 demand if and when any shortfall occurs.

Mr. Phillips testified that the concept of legacy costs and a transition charge is fraught with problems, constitutes unreasonable ratemaking, and should be rejected. He explained that the concept assumes industrial customers have not already paid a fair portion of the costs associated with the generation costs and have not saved other customers the avoided costs associated with new generation through self-supply or by accepting the risk of interruptible load.

Mr. Phillips testified that NIPSCO's current coal fleet was constructed between 33 and 45 years ago and that no customer is obligated to support costs for that duration. He said NIPSCO has not planned or constructed a baseload coal-fired generating facility in approximately 50 years and that NIPSCO has already closed two generating stations (Mitchell and Bailly) for various reasons, and NIPSCO plans on closing the remaining facilities in the near future. Mr. Phillips added that industrial customers have mitigated NIPSCO's need to add generation by taking interruptible service and investing in self-generation. He said the U.S. Department of Energy's list of combined heat and power installations in Indiana shows more than 1,300 MW of installed capacity at industrial plants in NIPSCO's territory. Mr. Phillips testified that all of NIPSCO's customers have benefitted historically due to the large industrials' acceptance of interruptible risk and private investment in self-generation, which resulted in less system resources NIPSCO had to build and maintain. He said it would be unbalanced and unreasonable to require those same customers to bear legacy costs. Mr. Phillips testified that customers of all classes are free to lower load, self-generate, or leave a service territory and said it is not appropriate to claim legacy costs from previous decades through a transition charge associated with load reduction.

In response to claims that the Rate 831 customers would be getting a subsidy, Mr. Phillips first noted that under NIPSCO's COSS, production costs are allocated to the Rate 831 customers based on the amount of capacity NIPSCO estimated they would use, which is cost-based ratemaking, not a subsidy. He also provided a history of the subsidies industrial customers have provided to other customer classes since NIPSCO's 1981 rate case. He calculated the subsidies the industrial customers have provided to other customer classes totaled $2.85 billion over the 20-year period from 1987 to NIPSCO's 2008 rate case. Conservatively, Mr. Phillips noted if the calculated subsidies were cut in half, $1.4 billion would still greatly exceed the alleged legacy costs. Consequently, due to the subsidies, large industrials have been paying revenue far in excess of their cost-based share and that excess revenue is much greater than the alleged legacy costs that the other witnesses propose to impose as a transition charge on Rate 831 customers.

Mr. Phillips also took issue with NIPSCO's response to CAC's DR 5-1, upon which Mr. Wallach relied. Mr. Phillips stated that the response inappropriately allocated fixed generation costs to interruptible load. He provided a correction that removed interruptible load from the four highest peaks to recalculate a normalized 4CP allocator. He stated the 2017 load data associated with interruptions used in the response is not normalized or indicative of the 2019 test year.

Mr. Phillips also responded to Mr. Watkins' comparison of the 4CP allocation percentages used in NIPSCO's last rate case to the allocation percentages used in this case. According to Mr. Phillips, there are two significant problems with the comparison. First, the loads in the current case

are reduced because of the lost BP load. Second, the loads used in the last rate case included interruptible load, whereas the current case only uses firm load for allocating production costs.

Mr. Phillips also addressed Mr. Watkins' alternative cost allocation methods, noting that to his knowledge, the Commission has never approved an allocation method that classifies and allocates production investment costs on an energy basis. Mr. Phillips described the problems with the various methodologies that Mr. Watkins discussed and noted that not only is the 12CP method not reflective of the cost causation on NIPSCO's system, but that many of the 12 monthly peaks contain buy-through loads by customers on Rider 775. He explained those buy-through loads should not be used to allocate production costs because NIPSCO does not plan for or build generation for interruptible load, and the interruptible customers have obtained the power from the market. He then recommend use of the 4CP method because it is most reflective of cost causation.

E. NLMK. Mr. Lahtinen reiterated that the 4CP allocation method proposed by NIPSCO was reasonable and appropriate considering the NIPSCO system load profile, and that the more energy-oriented alternative methods described by OUCC witness Watkins would undercut the basic purpose of the proposed industrial rate restructuring by unnecessarily shifting costs to large industrial loads. Mr. Lahtinen urged the Commission not to adopt such a counter-productive approach. Similarly, he urged the Commission to reject the "transition cost" proposals advanced by the OUCC and CAC. He observed that industrial rates have historically subsidized the rates of smaller consumers, and that setting Rate 831 to recover the system average return (i.e., to set the rate at "parity") is an essential element to combatting uneconomic industrial customer bypass. Mr. Lahtinen explained that, by proposing the imposition of a Rate 831 transition fee, those parties were espousing an extension of the inter-class subsidies that would produce rates for large industrial customers that might accelerate rather than deter bypass actions.

Mr. Lahtinen explained why the US Steel proposal to create voltage differentiated transmission charges within Rate 831 was problematic, insufficiently supported, and should not be adopted. He also explained that the provisions of the Rate 831 tariff that would extinguish Rate 831 contracts under certain circumstances were reasonable and necessary, and the concerns expressed by the OUCC in that regard were unwarranted.

F. Sierra Club. Mr. Allison responded to ICC witness Medine, ICARE witness Griffey, and Peabody witness Nasi, who argued that NIPSCO should not move forward with its plans to retire its coal units. Mr. Allison showed that the arguments of these witnesses are rooted in a series of inaccurate assumptions, mischaracterizations, and misleading statements.

He stated that NIPSCO's remaining coal units have been uneconomic (i.e., more expensive than available alternatives) for many years now. Contrary to the implication of the coal industry witnesses, these are not currently well performing units that will only become uneconomic if faced with substantial environmental compliance obligations. Rather, are units are already and continue to be a consistent economic burden for NIPSCO's ratepayers. He estimated that each remaining NIPSCO coal unit lost more than $100 million relative to the market from 2014 through 2018.

Mr. Allison explained that NIPSCO's coal units are likely to remain uneconomic irrespective of any environmental capital expenditures. Even if these units do not need to incur any expenses to comply with CCR regulations, ELG, or other federal environmental regulations,

near-term retirement would still be in the best interest of NIPSCO's customers because NIPSCO's coal units are already more costly than available alternatives. NIPSCO data indicates that, even in the absence of any environmental capital expenditures, continuing to operate its coal units would result in billions of dollars in NPV losses relative to alternative resources.

Mr. Allison stated Mr. Griffey's claim that NIPSCO's IRP analysis supports the continued operation of Michigan City Unit 12 is false and is rooted in a plainly misleading comparison. He explained that NIPSCO's analysis clearly indicates that retiring Michigan City in the near term would save ratepayers hundreds of millions of dollars. He also stated that Mr. Griffey's claim that it is not in the interest of ratepayers to retire Schahfer Units 14 and 15 in the near term is refuted by his own analysis. Mr. Griffey's analysis indicates that, even under a host of assumptions that are favorable to NIPSCO's coal units, retiring Schahfer Units 14 and 15 in 2023 rather than 2028 would save ratepayers more than $200 million. Mr. Allison testified that Mr. Griffey misstated the potential retirement dates considered by NIPSCO. He explained that the actual retirement dates evaluated by NIPSCO consistently show that retiring NIPSCO's coal units as early as possible is always the lower-cost choice, even in the absence of environmental expenditures.

Mr. Allison stated that Ms. Medine's suggestion that it was unreasonable for NIPSCO to include a carbon price in its base scenario is unpersuasive and is inconsistent with the practices of other Indiana utilities. He also stated that Ms. Medine's suggestion that keeping NIPSCO's coal units online longer will minimize rate shock is unsupported.

Mr. Allison testified that Mr. Nasi's claims that NIPSCO's retirement decisions improperly rely on CCR-related costs that will be incurred regardless of future retirement decisions are unsupported and baseless. He explained that uncertainty does not constitute a valid reason to delay a decision to retire the NIPSCO coal units. While uncertainty is inevitable in any major resource planning decision, the available evidence strongly supports the near-term retirement of NIPSCO's coal units. He added that NIPSCO's proposed industrial service structure change does not justify delaying coal unit retirement decisions.

Mr. Allison testified that fundamentally, the available evidence clearly indicates that NIPSCO's coal units are currently uneconomic and are very likely to remain that way. He concluded that NIPSCO should retire its remaining coal units as soon as is practicable and recommended that the Commission approve reasonable ratemaking treatment that will enable these retirements and their attendant ratepayer benefits.

G. US Steel. Mr. Georgis refuted claims that Rate 831 creates a cost shift to non-Rate 831 customer classes, explaining that presently a subsidy is built into the existing rate structure whereby Rate 831 customers pay disproportionately to the benefit of the remaining customer classes. Mr. Georgis explained that if Rate 831 customers were required to pay an annual $40.2 million transition charge as recommended by other parties, Rate 831 customers would be paying for infrastructure and services they do not use or receive any benefit. Mr. Georgis testified that a $40.2 million subsidization is not cost based, does not follow cost of service principles, and is inconsistent with NIPSCO's treatment of similar customers who reduce demand or generate all or a portion of their power. Mr. Georgis also refuted the OUCC's recommended transmission charge adjustment, noting that the Rate 831 customers should not be forced to purchase back-up and maintenance transmission service embedded in the Rate 831 transmission charges if the

customer accepts the risks and consequences associated with their self-generation, especially since customers desiring back-up and maintenance service can obtain it through Rider 876.

Mr. Georgis agreed with NIPSCO's 4CP allocation of production costs since the system is consistently a summer peaking system, which drives NIPSCO's production capacity investments. He reiterated that US Steel continues to actively evaluate additional cogeneration potential and although it withdrew its IDEM permit application pending the outcome of this proceeding, it has not foreclosed building cogeneration in the future. Mr. Georgis disagreed with Dr. Boerger's recommendation for a full adjudicated process for Phase 2 of the proceeding since the Phase 2 issues are limited in scope. Finally, Mr. Georgis recommended that the Rate 831 customers should decide amongst themselves how the $53.9 million of Tier 1 firm contract demand costs should be recovered, which eliminates the unintended consequence that penalizes one or more customers.

19. NIPSCO Rebuttal Evidence.

A. Mr. Hooper. Mr. Hooper addressed the other parties' testimony related to Rate 831, the OUCC's proposed credit mechanism to address return on and of unrecovered balances upon the retirement of Schahfer and Michigan City generating units, CAC's proposal for a comprehensive low-income program and various monthly reporting requirements, and IMUG's proposal to implement an MSP. He testified that NIPSCO believes a migration of load to either self-generation or other jurisdictions for much of its largest industrial load is imminent without a modification to a more competitive service structure as evidenced by discussions with and filings made by those customers supporting the intent to add or increase self-generation. He stated that a combination of these customer's scale, generation experience, and energy market sophistication make them uniquely positioned to take advantage of a proposal such as Rate 831. Likewise, those same traits are sufficient to motivate these customers to either shift operations or invest in additional generation assets when faced with inferior economics from NIPSCO's fleet.

Mr. Hooper disagreed with Mr. Blakley's proposed mechanism in which ratepayers are credited with the effect of annual depreciation expense associated with these extraordinary retirements beginning when new rates go into effect and prior to the units actual retirement dates. He stated that the OUCC and other parties consistently make the mistake of calling NIPSCO's extended recovery period for its retiring coal units as "accelerated" deprecation – which is not true. He noted that were NIPSCO to recover its remaining investments over the remaining useful life of these units, NIPSCO's depreciation rates would be much higher, resulting in a much higher revenue requirement. Instead, NIPSCO is proposing to extend its recovery period to ten years to reduce the rate impact. He also disagreed with OUCC suggestion that its "tracker mechanism" be put in place prior to the retirement date of the Schahfer units. He explained that if a capital tracker was approved, it should not be utilized solely for a one line item, but should allow for the recovery of all additional capital deployed during the recovery period.

In response to CAC's proposal for a comprehensive low-income program, Mr. Hooper testified that NIPSCO wants to implement a proposal that is easily and economically administered that can provide assistance to the most in need. He stated NIPSCO recognizes the demographics of its service territory and recognizes that while it offers a low-income program to its LIHEAP-qualified customers that heat with gas, it offers no additional programs for its LIHEAP electric

heating customers. He stated NIPSCO is continuing a stakeholder collaborative to reach agreement regarding additional assistance that can be offered to NIPSCO's low-income customers.

Mr. Hooper disagreed with CAC's recommendation for various monthly reporting requirements. He stated that NIPSCO already participates in an annual Performance Metric Collaborative where it reports on and discusses a host of key performance indicators. He indicated that in the Performance Metric Collaborative report filed by July 1 each year in Cause No. 44688, NIPSCO already provides monthly data for some of the items recommended by Mr. Howat and that additional items recommended by Mr. Howat could possibly be incorporated into the annual report without the added administrative burden that would be required if a separate monthly reporting process were implemented here.

Mr. Hooper agreed that IMUG's proposal to implement an MSP is worth further investigation. He stated, however, this is a program that would need substantial discussion amongst NIPSCO and interested parties. He explained that NIPSCO is willing to work collaboratively with IMUG to discuss the MSP and determine if such a program may fit into its existing generation portfolio. He stated that while he agrees with Mr. Sommer that an MSP could prove beneficial to many stakeholders, it is simply an idea that needs further vetting to ensure the appropriate parties are engaged and all aspects are thoroughly understood.

B. Mr. Kelly. Mr. Kelly stated that while Rate 830 is designed to provide service for NIPSCO's next largest group of industrial customers after Rate 831, the proposed rate is structured for a higher load factor profile. For the lower load factor customers within the rate design, it is likely that their increases would be higher than if the original designs of Rate 732 and 733 had been preserved. Mr. Kelly agreed with Mr. Phillips' recommendation that Rate 830 should be redesigned into two rates similar to the existing Rates 732 and 733. He testified NIPSCO is offering proposed Rates 832 and 833, which are designed as low load factor and high load factor rates similar to Rates 732 and 733. He explained that like the original Rate 830 proposed design, these proposed rates also include provisions for Back-Up, Maintenance, and Temporary Service.

Mr. Kelly testified Rate 831 retains retail service and is therefore not a retail wheeling or retail open access proposal and should not be rejected as incongruent with Indiana law or for failing to meet the requirement that NIPSCO provide retail utility service to its customers, as suggested by Ms. Medine. He stated Rate 831 preserves the bundled retail electric service these customers are served under today's Rates 732, 733, and 734 as well as the ability to purchase power at the MISO LMP during Rider 775 economic interruptions. He explained that Rate 831 only adds two additional features to NIPSCO's existing large industrial service structure: (1) the ability to firm up the customer's LMR obligation registered at MISO through the MISO capacity auction or a third party; and (2) the ability to bid a portion of the customer's load in the MISO portal (granted by NIPSCO) or purchase that portion of its energy from a third-party supplier. To accomplish these new options, NIPSCO still needs to facilitate the transactions as the MISO Market Participant whether by making the necessary registrations or by entering multiparty agreements for the benefit of the customer for capacity or energy. Mr. Kelly said that in retail open access markets, NIPSCO would not be involved at that level in those types of transactions but instead, NIPSCO would simply be wheeling the power and much of the activity would occur between the customer and third parties under MISO's tariff rather than with NIPSCO's involvement under NIPSCO's retail tariff. Said differently, NIPSCO is, by design, too involved in facilitating Tiers 2 and 3 (in addition

to the basic bundled firm service of Tier 1) to consider Rate 831 as retail wheeling or retail open access. Finally, he stated that if this was akin to deregulated retail wheeling, NIPSCO would remain the provider of last resort, which is not the case with Rate 831. He explained that Rate 831 requires a five-year notice for a customer to increase its Tier 1 firm contract amount, which protects NIPSCO's other customers from industrial customers "swinging" on its system.

Mr. Kelly testified Rate 831 is designed at parity in the ACOSS and is therefore not being proposed as a discounted service. Further, the identified cost shift to other customer classes for the reduced firm requirements of Rate 831 customers is just and reasonable because Rate 831 is not being subsidized by other classes since the rate is designed at parity. Finally, because the rate is fully costed, no "exit fee" should be assessed against the class to pay for "legacy costs" of the system as suggested by Dr. Boerger and Mr. Wallach. He explained that while the anticipated 184.556 MW of firm demand in Tier 1 (for the "original" five customers measured at the customers' meters) is lower than the amount of firm demand for which these customers have contracted with NIPSCO historically, the rate proposed for that 184.556 MW is at full cost without a discount. He said that still holds true now that an additional customer has been added to the proposed design after expressing interest in joining the rate rather than the originally proposed Rate 830. Mr. Kelly testified the transmission service is also not discounted under Rate 831. He stated that Rate 831 includes a fully costed charge for typical retail transmission service. He explained that for customers that have generating facilities (i.e., QFs) adjacent to their industrial premise, Rate 831 allows any outflows from the generator to be utilized at the industrial premise at a discounted charge for using NIPSCO's transmission system, but all other usage of NIPSCO's transmission system by those same qualifying customers and other Rate 831 customers will be charged at the fully costed transmission rate. Further, the discounted charge is only anticipated to apply to two of the six customers that would take retail service under the rate.

In response to the various challenges to Rate 831 proposing that Rate 831 should only be approved if something akin to an "exit fee" is charged to the participating customers, he understood the rationale offered in many of the arguments that NIPSCO's generation fleet was built to serve all customers including these Rate 831 customers. He stated, however, that these arguments are misplaced for three reasons. First, the idea of an exit fee borrows from policies in other states that have deregulated the generation function from traditional vertically integrated structures. He explained that in those states, the benefit of the bargain was that customers could enjoy the risks and opportunities of retail open access in exchange for buying their way out of the stranded costs of the utility that they would be leaving behind. He explained that the scenario NIPSCO and its other customers are facing is very different because here, large, globally competitive industrial customers with the financial and operational capability of building and operating their own internal generation are pursuing additional cogeneration solutions to avoid NIPSCO's vertically integrated cost to serve. When other states were deregulating, those customers seeking retail open access were not constructing their own cogeneration but were instead seeking access to other third-party generation capacity that already existed in the marketplace. Second, an exit fee would further exacerbate the situation that led NIPSCO to propose Rate 831 in the first place – NIPSCO's cost to serve exceeds these customers' cost to construct and own additional cogeneration facilities or otherwise significantly reduce their loads. Mr. Kelly testified that NIPSCO's proposed Rate 831 structure is a balanced proposal that seeks to preserve some fixed cost contribution from these largest industrial customers into the future. However, to the extent that these customers are faced with an exit fee that would completely offset (or worse) any savings they might achieve in the

MISO markets under Tiers 2 and 3, NIPSCO fully expects that they will continue to rationalize their internal loads with self-funded incremental generation capacity and other measures. He indicated that in that circumstance, the effort to charge a $40 million exit fee is going to lead to stranding the fixed costs associated with the 184.556 MW of firm service these customers would have otherwise paid under the Rate 831 proposal resulting in shifting even more costs to those classes in the long run as NIPSCO's largest industrial customers leave the system. Third, the industrial customers have already abandoned fully firm service from NIPSCO's generation resources years ago. Mr. Kelly noted that in the 1980s, the Commission recognized that it was appropriate for these industrial customers to receive something less than firm service from NIPSCO in exchange for a reduced rate. Because of that interruptible level of service, they have not been responsible for much of the need for additional generation for more than two decades. Mr. Kelly stated that for these reasons, proposals for an exit fee on Rate 831 should be rejected. He testified that if Rate 831 were approved but included a cost of service allocation that increased the fixed cost allocation (i.e., an exit fee), NIPSCO would need to withdraw its ARP proposal rather than implement the rate, and NIPSCO would propose a 90-day procedural schedule to address any rate structure alternatives for its large industrial customers currently served under Rates 732, 733, and 734 and the effects of those alternatives on the other issues in this case.

Mr. Kelly disagreed with Mr. Lahtinen's proposal for addressing the Phase 2 True Up by requiring a minimum of 30,000 kW of Tier 1 service under Rate 831 except in circumstances when a customer's historical firm amount was less than 30,000 kW. Instead, NIPSCO proposed that if the five largest industrial customers are unable or unwilling to subscribe to the 184,556 kW in total under the proposed design, a 90-day procedural schedule be established to address the proper allocation of the 184,556 kW among the five largest customers or any rate structure alternatives that parties may offer for its large industrial customers currently served under Rates 732, 733, and 734. He indicated that to the extent other classes outside of Rate 831 are affected, NIPSCO's pro forma revenue requirement and ACOSS may also need to be revisited.

Mr. Kelly testified that NIPSCO only had four other qualifying customers under Rates 732 and 733 and had assumed that none of those customers would take service under Rate 831 because their firm load was not significantly higher than ten MW. However, now one of the four remaining qualifying customers intends to take service under Rate 831. He explained that NIPSCO's testimony was written to isolate the Phase 2 True Up to specifically manage the uncertainty of the subscription for NIPSCO's five largest customers. He said that in order to avoid an insurmountable level of cost shift to other classes, the industrial service structure was proposed at that 184,556 kW of Tier 1 service for those five largest customers. Mr. Kelly testified that although another customer has expressed intent to participate in Rate 831, the incremental impact between its participation in Rate 831 versus the prior Rate 830 is minimal in the final proposed design of Rate 831 because most of the load that would be available to participate in the non-firm Tiers 2 or 3 is minimal and is partially served on NIPSCO's interruptible (and curtailable) Rider 775 today. He testified that based on the revised Phase 2 True Up proposed here, this sixth customer is likely to sign up for the minimum 10,000 kW of Tier 1 firm service which would be very close to the customer's historical level of firm service.

Mr. Kelly agreed with US Steel witness Thornton that additional information regarding the contractual requirements of Rate 831 would be helpful to customers and third parties seeking the ability to transact under Rate 831. He noted that Mr. Westerhausen is sponsoring a contract that

can be used between NIPSCO and Rate 831 customers, and Mr. Campbell is providing additional detail on the required terms of the multiple-party contract among NIPSCO, its Rate 831 customer, and a third-party capacity or energy supplier. Mr. Kelly disagreed with Mr. Thornton's assessment that additional time will be needed for customers to implement Rate 831 assuming an order is received by the end of August 2019. He stated that NIPSCO is proposing that any qualifying customer that is unable to take service under Rate 831 be placed on either proposed Rate 832 or 833 as a temporary "sub"-rate within Rate 831 with the requirement that the customer also maintain any historical curtailable service (MISO LMR registration) under prior Rider 775 through the end of the current MISO 2019/2020 Planning Year. He explained that NIPSCO is not proposing that Rider 775 or its monthly bill credit would continue as a service structure once the 800 series rates go into effect, but any customer unable to take service under Rate 831's Tiers 1, 2, and/or 3 that also had a Rider 775 LMR registration be required to maintain it through the current 2019/2020 MISO Planning Year. He said that while the customers will be required to subscribe to their portion of Tier 1 service in the Phase 2 True Up once the rate takes effect, this approach will provide the necessary bridge for any customer that is not able take service immediately under Tiers 1, 2, and or 3 of Rate 831. Mr. Kelly testified NIPSCO has identified a process for assisting customers in addressing their MISO LMR exposure when activating their Rate 831 service. He explained that after discussions with customers, NIPSCO is proposing that customers be able to purchase any MISO Zone 6 ZRCs associated with the customer's existing firm load that is transferring to Rate 831 above their Tier 1 firm election. Further, to assist customers with procuring additional ZRCs from third-party suppliers during the 2019/2020 planning year, NIPSCO is also offering to conduct a RFP in the coming months for the benefit of its Rate 831 customers, allowing them as many tools as possible in firming up their LMR obligations should they so desire when activating their Rate 831 service. NIPSCO believes this approach will address the concerns raised by Mr. Thornton.

Mr. Kelly agreed with Mr. Thornton that additional information would help clarify how proposed Rate 831 will be implemented. He stated that after discussions with customers expected to take service under proposed Rate 831, NIPSCO is proposing that the five-year contract requirement be adjusted so that it can synchronize with the completion of the last MISO capacity planning year that would be in effect. He indicated that failing to align the contract terms with the closure of the planning year could result in a scenario where a customer's firm and non-firm capacity requirements are changing intra-year without the ability to address that change easily and seamlessly through the annual auction process. Therefore, NIPSCO is proposing that the contract would expire the later of five years from the contract's signing date or the completion date of the last MISO Planning Year in effect during the five years that the contract would otherwise cover.

Mr. Kelly testified that to clarify confusion with curtailment of LMRs under Rate 831 and interaction with Rider 876, LMRs under Rate 831 Tiers 2 and 3 will be registered along with a firm service level including both Tier 1 and any additional capacity procured for Tiers 2 and 3. This firm service level will set a clear floor that customers curtail to in the event MISO exercises the curtailment of the entire LMR capacity registered. He explained that like today under Rider 776, additional services granted under Rider 876 for back-up and maintenance service will not alter this firm service level. As such, NIPSCO proposed language to clarify that service under Rider 876 cannot be used to nullify some or all of a MISO LMR obligation to curtail. Mr. Kelly noted that in instances where MISO does not ask for the entire LMR capacity, customers will only need to drop the requested relief sought by MISO. He clarified that in instances where a customer

can be entirely firm under Rate 831 and is taking service under Rider 876, during times of curtailment, Rider 876 is subject to curtailment when curtailments under Rate 831 are insufficient.

Mr. Kelly testified that if the Commission does not approve the proposed industrial service structure or makes material modifications to which NIPSCO does not agree, NIPSCO is proposing that a 90-day procedural schedule be established to address any alternatives that parties may offer for its large industrial customers currently served under Rates 732, 733, and 734 and the effects of those alternatives on this case's other issues. He explained that Rate 831 directly affects the revenue requirement, specifically the fuel and related expenses. Accordingly, if NIPSCO doesn't have a final determination on the rate structure for these large industrial customers, then NIPSCO doesn't have a final revenue requirement or ACOSS and cannot implement new rates for any customer class.

C. Ms. Shikany. Ms. Shikany addressed various revenue requirement issues and pro forma adjustments raised by the parties, discussed normal retirement accounting, provided actual utility plant in service, associated depreciation, and capital structure at December 31, 2018 (removing two TDSIC projects from the Seven-Year Electric TDSIC Plan Regulatory Asset included in rate base in RB 11-R and AMTZ 5-R), provided updated projections for utility plant in service, associated depreciation, and capital structure at June 30, 2019, and December 31, 2019 (based on actual amounts recorded through December 31, 2018, with the addition of forecasted 2019 activity obtained from or based upon assumptions in NIPSCO's 2018 AFP, and updated Electric Rate Case Amortization Expense based on the most current rate case expense estimates), and presented revised schedules supporting NIPSCO's revenue requirements reflecting its rebuttal positions, including: (1) Operating Revenues / Fuel & Purchased Power to (a) eliminate an inconsistency between Mr. Chriss' analysis of load profile and that utilized in NIPSCO's COSS and (b) to reflect an additional migration for one large industrial customer from current Rate 730 to Rate 831; (2) Rate Base, Depreciation Expense, and Amortization Expense to reflect rate base amounts concurrent with current projections of utility plant in service at both June 30, 2019, and December 31, 2019, updating the accumulated depreciation, depreciation expense, and amortization expense associated with these amounts, and updating electric rate case amortization expense based on the most current rate case expense estimates; and (3) WACC to reflect capital structures concurrent with current projections at both June 30, 2019, and December 31, 2019.

Ms. Shikany disagreed with Mr. Eckert's proposal that Uncollectible Expense be based on a two-year average because he removed 2015 in NIPSCO's proposed three-year (2015-2017) average because he believes 2015 was significantly higher than 2016 and 2017. She explained the write off as a percentage of revenues was 0.59% in 2015, 0.31% in 2016, and 0.35% in 2017 and noted that write-offs as a percentage of revenues ranges from 0.31% to 1.08% during the last ten years (2008-2017) with two years in which write-offs as a percentage of revenues exceeded that in 2015. She testified the OUCC's calculation is not reasonable because it produces the lowest level of write-offs as a percentage of revenues in each of the ten scenarios.

Ms. Shikany disagreed with Mr. Eckert's proposed reduction to Vegetation Management Expense based on a five-year historical average budget growth rate. She explained that NIPSCO's proposed rates are based on a forward-looking test year (January 1, 2019 – December 31, 2019) and that NIPSCO's 2018 AFP is the underlying basis for its rate request, which is consistent with Ind. Code § 8-1-2-42.7. She testified that unlike Mr. Eckert's calculation based on rolling forward

the 2018 budget amount by the average five-year (2014 – 2018) historical growth in budget, the amount that NIPSCO included is projected data for the forward-looking test year, which is consistent with NIPSCO's budget methodology and based on price times a quantity calculation.

Ms. Shikany disagreed with Mr. Eckert's proposed decrease in depreciation expense because NIPSCO was unable to validate the mathematical accuracy of his proposed adjustment. She testified that NIPSCO's proposed level of depreciation expense was calculated by multiplying NIPSCO's forecasted original cost of utility plant in service by the proposed depreciation accrual rates. She noted that Mr. Eckert did not oppose NIPSCO's proposed rate base but that when NIPSCO multiplied its projected original cost rate base by the OUCC's proposed depreciation accrual rates, it could not reproduce the OUCC's calculation.

Ms. Shikany disagreed with Mr. Lahtinen's characterization of early accelerated recovery. She testified that NIPSCO has not proposed to "accelerate" depreciation but instead conducted a depreciation study and presented depreciation rates that match the expected life of the units – that is not "acceleration" but simply the proper function of depreciation. She described that NIPSCO has offered to defer the recovery over a longer period of time than the units' estimated useful lives. She explained that depreciation studies are prospective and any future accruals of the depreciable property should be amortized over the remaining service life of the property. She stated that when NIPSCO made capital investments that increased the average service lives of certain electric plant accounts, thereby extending the return of its capital investments, no parties objected.

In response to Mr. Gorman's proposal that ECRM Tracker Deferred Expenses be amortized over four years instead of two years as proposed by NIPSCO, and his concern that if NIPSCO amortizes over a two-year period but the base rates remain in effect for four years, then NIPSCO will recover more than double the estimated ECRM deferred costs, Ms. Shikany explained that NIPSCO proposed to amortize these amounts over a two-year period, which is the approximate length of time it would take to recover these costs through the currently approved ECRM Tracker. She stated that consistent with past practice and as recommended by Mr. Eckert in this proceeding, NIPSCO would make a compliance filing to reduce base rates when the amortization of each regulatory asset is complete, which eliminates this risk.

Ms. Shikany disagreed with Mr. Blakley's proposed decrease in income tax expense due to a five-year amortization period for unprotected excess ADIT. She indicated that if Mr. Blakley's proposal is accepted, NIPSCO should be authorized to make a compliance filing at the end of the amortization period to increase its rates accordingly. In response to Mr. Eckert's proposal for a different adjustment to synchronized interest expense, she explained that synchronized interest expense is calculated by multiplying rate base by the cost of long-term debt. As noted by OUCC witness Eckert, the OUCC did not oppose NIPSCO's proposed rate base or cost of debt. She stated that the difference in NIPSCO's and the OUCC's calculation appears to be due to rounding.

Ms. Shikany explained NIPSCO's basis of accounting required by the Commission, including the level of detail the Uniform System of Accounts requires of NIPSCO to maintain its plant records, guidance on the level of detail required when recording additions and retirements, and guidance on how to account for retirements. She testified that in accordance with Uniform System of Accounts guidance, NIPSCO credited Utility Plant in Service and debited Account 108, Accumulated Provision for Depreciation of Electric Utility Plant in amounts equal to the original

cost of the asset, which results in no change in the net book value of rate base. She stated that this resulted in a debit balance in accumulated depreciation of $102,923,994 and $142,329,364, for Unit 7 and 8 respectively, which represents the estimated remaining net book value at the date of the physical retirement. Ms. Shikany noted that the Uniform System of Accounts does not offer any alternatives to this methodology. She stated that the Uniform System of Accounts provides further instructions on Depreciation Accounting and that NIPSCO utilized the composite method referenced in those instructions. She testified that consistent with past requests and Commission rulings, NIPSCO is seeking approval of depreciation rates on a FERC account-by-account basis, not by a FERC account-by-account-by-generating station basis.

Ms. Shikany stated that an extraordinary retirement occurs only if the Commission, by order, directs that upon retirement the remaining net book value be recorded as a regulatory asset. She explained that NIPSCO is seeking Commission approval to treat the retirements of Schahfer and Michigan City generating stations as extraordinary and that NIPSCO is seeking approval well in advance of these retirements to: (1) establish a regulatory asset in an amount equal to the remaining future accruals at the date of retirement; (2) defer regulatory recovery of these amounts through 2030; and (3) include this regulatory asset in NIPSCO's calculation of rate base in subsequent base rate proceedings.

D. Mr. Scott. Mr. Scott responded to opposition to the pro forma labor and benefits that NIPSCO presented in its case-in-chief by Mr. Eckert and Mr. Gorman. He noted that in the event that vacancies are not filled, or these vacancies are filled, but other vacancies arise, there will not necessarily be a corresponding decrease in labor cost because the work must still be done and is often filled by overtime or outside contractors.

In response to the proposed adjustment to benefits expense, Mr. Scott testified that NIPSCO's budget in actuality understates the total benefits expense. He stated that in theory, NIPSCO should have built the budget based upon a benefits-per-employee calculation, but instead, it is based upon the actual headcount as reported in the actuarial reports. As such, adjusting labor benefits for vacancies has already been factored into the budget numbers.

E. Mr. Augustine. Mr. Augustine addressed the perceived issues with NIPSCO's 2018 IRP raised by Mr. Griffey, Ms. Medine, and Mr. Nasi. In response to Ms. Medine's claim that the IRP has not been approved and thus cannot be used to support elements associated with this rate case, he stated that the IRP is a planning document and is not subject to a ruling or formal approval by the Commission. He testified that as part of its transparent IRP process, NIPSCO conducted six public advisory meetings over the course of 2018, along with many other individual meetings with stakeholders to provide information and receive feedback on the methodologies and assumptions used in the IRP. He noted that as part of this process, NIPSCO performed several stakeholder-requested analyses prior to submission of the IRP, including some requested by Ms. Medine and the ICC.

Mr. Augustine summarized the general process NIPSCO undertook to evaluate retirement and replacement decisions in its IRP. In response to Ms. Medine's suggestion that NIPSCO should have performed a single optimization analysis to identify the preferred retirement plan for the coal units, Mr. Augustine testified that if NIPSCO would have performed a single, least cost

optimization analysis, the IRP models would have determined that the optimal portfolio would be to retire all coal units as soon as possible.

In response to Mr. Griffey's claims that NIPSCO only applied flexibility to its future selection of resources after making an inflexible choice on early plant retirement dates, Mr. Augustine testified that NIPSCO actually concluded that retiring coal earlier than the dates outlined in the preferred portfolio would be the least cost portfolio outcome. He explained that NIPSCO found that retirement of units at Schahfer as early as 2021 would provide savings for customers, but concluded that early retirement was not executable by 2021, given the required transmission upgrades that must be made to ensure system reliability. He also explained that NIPSCO found that retiring Michigan City in 2023 provided the greatest cost savings to customers, but concluded that a change of over 75% of NIPSCO's physical generation at one time in 2023 would create potential reliability and execution risk for customers. Thus, NIPSCO concluded that a 2028 retirement date for Michigan City would allow for a more orderly portfolio transition and provide an ability to gain access to better information regarding technology change and future customer demand. He stated that if NIPSCO had not applied flexibility in its retirement decision, the preferred portfolio would have called for retirement of the units as early as possible.

In response to Mr. Griffey's criticism of the number of scenario/portfolio combinations that were evaluated and his statement that NIPSCO should have constructed evaluations of different retirement dates that changed by scenario, Mr. Augustine testified that NIPSCO's analysis evaluated a very broad range of retirement dates across a range of scenarios and stochastics. He explained that the primary point of evaluating eight different retirement date combinations for the coal fleet across all scenarios and stochastics was to provide a highly transparent analysis of different retirement strategies against different potential market outcomes. He stated that instead of limiting the evaluation of flexibility, as Mr. Griffey suggests, this approach actually allowed NIPSCO to evaluate the performance of different portfolios against changing market assumptions over time.

Mr. Augustine disagreed with Mr. Griffey's claim that by using a two-step approach and never comparing the results across steps, NIPSCO arrives at an inappropriate conclusion in its IRP. Mr. Augustine noted that Mr. Griffey's claim fails to acknowledge the rationale behind the two-step process and the multiple objectives NIPSCO evaluated in its review of retirements and replacement options. He testified that NIPSCO performed retirement analysis in multiple phases against different resource alternatives and concluded that early retirement of coal units was cost effective for customers. He explained that NIPSCO then performed a replacement analysis to evaluate the replacement alternatives through a more comprehensive set of parameters and scoring mechanisms, including a portfolio diversity component to test natural gas and renewable replacements and a commitment duration component, where a mix of PPA and ownership options were evaluated. He testified that resource planning decisions were made based on an integrated scorecard approach and not purely on least cost, which is why certain retirement dates are staggered and why a mix of replacement alternatives was proposed in the preferred portfolio.

Mr. Augustine testified that Mr. Griffey's comparison to show that an alternative retirement plan would have been more cost effective than NIPSCO's preferred portfolio is an apples-to-oranges comparison and ignores the other objectives evaluated by NIPSCO in the replacement analysis. He explained that NIPSCO found that a wide range of resource alternatives

were lower cost than operating and maintaining the existing coal fleet. He concluded that Mr. Griffey did not conduct any dispatch or portfolio analysis that would demonstrate a different outcome under his proposed alternative approach.

In response to Ms. Medine's contention that NIPSCO did not properly account for recent changes in delivered coal price expectations for 2019 in the IRP and that NIPSCO did not fully consider all realistic commodity price combinations, Mr. Augustine stated that the difference in assumed coal price raised by Ms. Medine for the fleet averages about $0.13/MMBtu, which represents around a little more than $1/MWh, less than 5% of the total variable costs for the units, which is not a significant difference in the context of other drivers of the IRP analysis, including natural gas prices, which dropped even further since the development of the IRP assumptions. He also stated that NIPSCO's 2018 IRP assessed portfolio performance across a wide range of coal and natural gas prices precisely because future market conditions are uncertain and will inevitably be different than any single point forecast. In response to Ms. Medine's critique that NIPSCO did not appropriately consider a scenario without a carbon price and with high gas prices, Mr. Augustine testified that as part of its 2018 IRP stakeholder process, NIPSCO evaluated a scenario developed by the ICC and Ms. Medine that had the same assumptions she claims NIPSCO ignored. He stated that this scenario had no CO2 price, flat coal prices, and high natural gas prices. He noted that the results from this scenario were consistent with the other four scenarios, concluding that retiring coal capacity early provided substantial cost savings to customers.

Regarding Mr. Griffey's assertion that NIPSCO did not properly account for expected solar cost declines over the long term, Mr. Augustine testified that as Mr. Griffey recommended, NIPSCO directly calibrated its generic solar cost projections to results from the RFP and assumed a $1,006/kW (real 2017$) cost for 2023 additions, which is a cost *lower* than Mr. Griffey's recommendation. Mr. Augustine further explained that Mr. Griffey's claim that inaccurate solar cost assumptions were used in the IRP analysis was false due to his failure to account for ongoing coal maintenance capital expenditures, accelerated tax depreciation benefits for solar, and differences in generic solar additions in his calculations.

In response to Mr. Griffey's belief that NIPSCO underestimated the capacity value associated with wind resources, Mr. Augustine noted that historical data for wind plants operating in Indiana is not a reasonable way to project future capacity credit values for new assets. Regarding Mr. Griffey's belief that NIPSCO underestimated the potential of future wind output degradation, Mr. Augustine testified that ongoing maintenance will limit the amount of degradation seen at the future wind facilities and that the IRP analysis included these costs. He explained that while solar bidders to the RFP provided specific information regarding degradation curves, wind bidders did not offer such information, so NIPSCO did not include any assumptions for this factor in the IRP analysis. He noted that Mr. Griffey did not attempt to quantify the potential impact of any degradation, nor did he present any data regarding wind degradation that would suggest he has better information than the RFP bidders, all experienced wind developers. Furthermore, Mr. Augustine noted that NIPSCO does not view this factor as having a meaningful impact on cost outcomes, especially given the large cost savings associated with wind additions to the portfolio.

In response to Mr. Griffey's concerns with the maintenance capital expenditure projections used in the 2018 IRP, Mr. Augustine testified that NIPSCO's capital expenditure projections are consistent with expectations of future operations. He explained that retiring a plant early reduces

the expected maintenance capital that is required, due to a reduced need to continue investing in the asset for long-term use, which is an important reality that must be incorporated in an IRP analysis. He stated that Mr. Griffey neglects this reality and seems to think that maintenance capital plans should be the same regardless of when a plant is expected to retire. He said that Mr. Griffey's proposed approach ignores significant cost savings that are associated with retirements.

Regarding cost assumptions relating to ELG and CCR compliance and treatment of potential CO2 costs, Mr. Augustine testified that NIPSCO evaluated different means of ELG compliance and conservatively developed its final set of portfolios around the assumption that plants could achieve compliance through a non-ZLD approach. He noted that NIPSCO evaluated a retirement portfolio that extended the retirement date of Schahfer Units 14 and 15 to 2028 under the assumption that ELG compliance could be achieved through a retirement in that year as opposed to a specific control mechanism by an earlier date. He stated that although NIPSCO's four *scenarios* do not envision compliance obligation changes associated with ELG and CCR Rules, NIPSCO evaluated potential changes in compliance obligations in the *portfolio* development process. He noted that in its 2018 IRP stakeholder process, NIPSCO performed an analysis of the coal retirement economics requested by Ms. Medine and the ICC with *no* new environmental capital incurred at the coal plants – effectively a scenario where no environmental compliance is required over the entire planning period – in which NIPSCO found that retiring coal early still provided significant savings to customers. With regard to treatment of potential CO2 costs, Mr. Augustine stated that NIPSCO evaluated a range of potential CO2 price futures, including a customized scenario requested by the ICC. He explained that while the two CO2 price trajectories developed in the 2018 IRP include a CO2 price starting in 2026, NIPSCO also analyzed scenarios without any CO2 price for the *entire* IRP forecast horizon. He testified that the results of this scenario concluded that retiring coal capacity early would lead to significant savings for customers and that NIPSCO also performed an analysis of the coal retirement economics requested by the ICC with no CO2 price, high natural gas prices, flat coal prices, and no incremental capital, and still found that retiring coal early provided significant savings to customers.

Mr. Augustine responded to general concerns regarding NIPSCO's IRP analysis identified by Mr. Griffey and Ms. Medine, including concerns regarding NIPSCO's incorporation of potential congestion risk, ancillary services costs, and the new proposed industrial rate structure; a claim that NIPSCO has not performed its revenue requirement calculation properly; and a claim that certain retirement portfolios cannot be properly compared due to inconsistent assumptions. He stated that NIPSCO acknowledged the existence of congestion and nodal price risk for certain resources in its 2018 IRP and noted that this would be evaluated in further resource selection processes associated with the RFP, as was done in NIPSCO's analysis for its recently pursued wind resource additions. He stated that while it is possible that MISO-wide ancillary services costs will increase in the future, Mr. Griffey did not provide any actual evidence or analysis to support his implication that NIPSCO's preferred portfolio would face higher net costs than a portfolio that retains coal. With regard to future industrial load uncertainty, Mr. Augustine testified that NIPSCO did evaluate a low-load scenario, which was based on substantial industrial load leaving the system. He noted that although it was combined with other factors that differed from the Base Case and although it was not based on specific assumptions regarding lower industrial firm demand that may materialize from a new rate structure, it found that retiring coal units provided savings to customers. He stated that any loss of firm load can be managed through NIPSCO's procurement

of replacement resources, while investing in and maintaining the high-cost coal units could result in more high-cost capacity than necessary if load obligations were to fall significantly.

Mr. Augustine testified that Ms. Medine's statement that NIPSCO's NPV approach assumes levelized recovery of capital investment is a false assertion. He explained that Ms. Medine's claim shows a lack of understanding of how NIPSCO conducted its IRP analysis, since NIPSCO did not levelize capital expenditures but instead performed a revenue requirement calculation that puts new capital into rate base as units enter into servicing, resulting in NIPSCO earning a return of and on that new capital over time. As a result, the recovery of new capital is front-loaded in NIPSCO's analysis, meaning that customers pay more in the first year than in subsequent years, contrary to Ms. Medine's claims. In response to Mr. Griffey's suggestion that he was unable to compare the economics of retiring Schahfer Units 17 and 18 versus the alternatives because the portfolio that holds all coal through end-of-life does not include new DSM and EE measures beyond what is currently in NIPSCO's approved plans, Mr. Augustine testified that the purpose of the IRP is to compare current resources with alternatives, whether they be demand- or supply-side options, as NIPSCO has done. He explained that in evaluating different portfolio options within similar reserve margin constraints, alternatives such as DSM and other supply-side resources are only needed when coal units retire.

Mr. Augustine concluded that while the 2018 IRP involved a complex set of portfolio analyses, including hourly dispatch analysis and detailed revenue requirement projections, the simplest explanation for NIPSCO's preferred portfolio is that the *all-in* costs of acquiring and operating new renewable resources are far lower than the expected costs of continuing to maintain and operate NIPSCO's coal units. He testified that in the IRP, the all-in costs for PPA or NIPSCO-owned renewables over their expected operating horizons ranged between approximately $25/MWh and $51/MWh (nominal $) and that over the same period, the *variable-only* costs for the coal fleet associated with coal expenses and variable operations and maintenance costs are close to or even higher than the *all-in* costs of many of the renewables options. Therefore, any additional costs for the coal plants associated with fixed operations and maintenance activities, new capital investments, or future carbon regulations all raise the costs substantially higher than new renewables. He stated that even in scenarios where these other costs are eliminated or dramatically reduced, retiring the coal plants and replacing the energy and capacity with renewables is a lower cost outcome.

F. Mr. Hooper. Mr. Hooper responded to the OUCC's proposal to limit the adjustment of Forward Test Year Vegetation Management expense to a five-year average value. He testified that NIPSCO's clearance distances are designed to provide adequate clearance at time of trimming to allow for vegetation growth with minimal impact to system reliability until the next trim cycle. He explained that while Mr. Eckert's analysis is mathematically correct, it fails to consider the benefits of maintaining a 1,500 mile clearance goal and fails to account for the fact that the costs of vegetation management continue to climb. He noted that the OUCC did not challenge the underlying facts supporting the rationale for the proposed increase in Vegetation Management expense and contended that reducing the requested amount by $1.3 million would not be representative of the ongoing cost of those activities.

G. Mr. Carmichael. Mr. Carmichael responded to criticisms from Mr. Nasi that regulatory timelines NIPSCO assumed for compliance with the EPA's CCR and ELG Rules were

too short because of available extension options and EPA's plans to reform those rules and that assumed capital and O&M expenditures were too high or not properly supported. Mr. Carmichael explained the overall process NIPSCO utilized to determine the anticipated compliance timelines and environmental cost estimates that were utilized in NIPSCO's 2018 IRP, including how NIPSCO determined compliance timelines based on a plain reading of the rules and regulatory agency guidance and how available extensions were considered and applied. He discussed how NIPSCO utilized expert third-party consultants with extensive industry experience, internal expertise, and available industry data to determine the capital environmental cost estimates used in the IRP and reviewed the potential options for meeting compliance these experts provided to assist in selecting technical solutions/projects. NIPSCO also balanced current and future compliance obligations with operational needs and overall cost to choose a compliance option; the estimates were then adjusted to align with the estimated annual spend to complete a project; and dollars were applied to the estimates for owner's costs, indirect costs, and escalation. In each instance, NIPSCO utilized the most reasonable compliance alternative and estimated cost and used its best judgment. However, Mr. Carmichael noted that, when predicting the future state of environmental regulatory compliance, there will necessarily be some uncertainty.

Mr. Carmichael also explained why it is important for NIPSCO to include its best estimate for environmental compliance costs in its long-term planning, including in its 2018 IRP. While there is uncertainty around practically all major environmental rules, he stated that NIPSCO must make judgments about many things, including environmental rules, when making important decisions like what generation will best position NIPSCO to serve its customers in the future. NIPSCO also cannot assume no compliance costs for a rule that is subject to challenge or reconsideration. He noted that Mr. Nasi criticized NIPSCO's environmental compliance cost estimates used for the 2018 IRP but nowhere provided his own cost estimates. Because NIPSCO conducted detailed cost estimation using proven methodologies and in coordination with its expert consultants, Mr. Carmichael stated that Mr. Nasi's criticisms are unwarranted.

With respect to compliance with the ELG Rule, Mr. Carmichael summarized Mr. Nasi's criticism that NIPSCO has overstated the compliance costs. Mr. Carmichael reviewed the current status of the ELG Rule and noted that NIPSCO incorporated lower ELG costs and adjusted timing assumptions in the 2018 IRP as a result of EPA's yet-to-be-finalized reconsideration of the ELG Rule. He explained that Michigan City Unit 12 is already compliant with the ELG Rule and why the "Postponement Rule" discussed by Mr. Nasi has no bearing on the NIPSCO ELG compliance timing for the Schahfer Generating Station assumed in the IRP for 2023. He also testified that there is no indication the ELG Rule and related requirements will go away completely and how NIPSCO changed assumptions in the 2018 IRP to: (1) lower ELG costs with the assumption that EPA would relax the 2023 ZLD requirement; and (2) assume that a non-ZLD option would be allowed at Schahfer for FGD wastewater. For bottom ash transport water, Mr. Carmichael explained that Schahfer Units 14 and 15 are already retrofitted for compliance with the CCR Rule; thus, there are no additional cost or timing issues related to ELG. Regarding Schahfer Units 17 and 18 bottom ash transport water, he explained that it would be likely that bottom ash transport projects (like those for Units 14 and 15) would be required and that NIPSCO's assumed cost estimates were similar to those projects it has already installed at Units 14 and 15. He clarified that the settlement in Cause No. 44872, which addressed CCR compliance projects but not ELG compliance projects, does not in any way invalidate cost estimates or timing assumptions in the 2018 IRP, nor does it demonstrate that NIPSCO will not be required to comply with the ELG Rule in the future.

Regarding the CCR Rule, Mr. Carmichael noted Mr. Nasi's criticism of NIPSCO's cost estimates. Mr. Carmichael explained that NIPSCO considered all options available under the CCR Rule regarding compliance timelines and costs. He stated that NIPSCO must make decisions and implement compliance plans to meet currently existing requirements even though the rule is undergoing reconsideration. If NIPSCO did not do this and instead waited for a final EPA decision, generating facilities may be forced to shut down early (October 2020 or earlier) to avoid non-compliance with the regulations. Mr. Carmichael testified that this risky approach would be inconsistent with NIPSCO's commitment to provide reliable service to its customers. He also testified about the CCR compliance options that were prepared by third-party consultants and those agreed to in the 44872 Settlement, which have been executed on budget by NIPSCO. He stated that this demonstrates NIPSCO's cost estimates for Schahfer Units 14, 15, 17, and 18 and Michigan City Unit 12 are reasonable. Mr. Carmichael also clarified that his discussion of certain CCR ARO costs, which NIPSCO is not seeking to recover here, was not related to the 2018 IRP. Based on a recent court decision, he also stated that NIPSCO disagrees with Mr. Nasi and does not anticipate that CCR Surface Impoundments will be allowed to continue to receive CCR and non-CCR wastewater in the future.

Mr. Carmichael next addressed criticisms about NIPSCO's compliance plan for the MATS Rule. He specifically disagreed with Mr. Nasi's assertion that NIPSCO's inclusion of MATS-related O&M costs in the 2018 IRP was unreasonable. Mr. Carmichael explained that the MATS Rule's requirements are still in effect, and NIPSCO must continue to comply with them. Because the MATS Rule remains effective and it is unlikely that EPA will withdraw MATS entirely or drastically alter the rule, NIPSCO has assumed it will continue to incur compliance costs for the time in which the impacted generating units operate and, thus, made no changes in its MATS compliance plans. He also noted that the majority of the O&M costs to comply with MATS come from operation of the FGD systems; thus, even if EPA were to repeal MATS, the FGDs would be required to continue to operate for purposes of compliance with other EPA rules, and the FGD-related O&M costs would continue to be incurred. More broadly, Mr. Carmichael criticized Mr. Nasi's advocacy for a "wait-and-see approach" to compliance, providing examples of how this previously would have resulted in coal-fired generation that would not have had control equipment installed in time for compliance and thus would have been non-operational for years. This is why it would not be prudent for NIPSCO to utilize this wait-and-see approach and assume that CCR, ELG, MATS, or other EPA rules will result in no future cost.

Regarding NIPSCO's path to compliance with CSAPR, Mr. Carmichael responded to Mr. Nasi's critique that NIPSCO failed to adequately justify the selection of SCR technology over the less expensive SNCR technology. After discussing NIPSCO's response to Peabody Request 1-010, included as Attachment No. MJN-5 to Mr. Nasi's testimony, Mr. Carmichael further explained the operational characteristics of Schahfer Units 17 and 18. He testified that installation of SNCR technology would not reduce NOx emissions below the current allocation. On the other hand, SCR technology can achieve a NOx rate that would bring Schahfer Units 17 and 18 in-line with the current NOx allocation rate. While SCR is a more capital-intensive technology, if the EPA continues the historical trend and lowers the ozone standard below 70 ppb, as expected during the IRP planning horizon, or if additional environmental regulations are promulgated that impact the relevant emission requirements, it is likely that SNCR technology would not be able to achieve compliance without a significant curtailment of coal-fired generation to achieve compliance or significant reliance on allowances in future NOx markets, assuming that the markets exist at a

price that justifies running coal-fired units. He added that if NIPSCO implemented SNCR technology and incurred the associated capital costs and later needed to comply with more stringent standards, SCR technology would likely need to be implemented at a significantly higher cost than implementing SCR technology in the first instance. Mr. Carmichael summarized that without SCR, NIPSCO's operational flexibility—its ability to run Schahfer Units 17 and 18, if at all—would become increasingly constrained as EPA implements the 70 ppb ozone standard and future standards. Regarding "operational flexibility" that SCR technology would allow, he explained that NIPSCO was speaking about the ability to continue to ramp output of the relevant units to meet system needs while also complying with current and future regulations because SCR allows units to operate over a wider range of output at lower emission rates than SNCR allows. Based on the operational characteristics of NIPSCO's generation fleet, existing and expected regulations, and as advised by internal and external subject-matter experts, NIPSCO believes SCR technology is the most appropriate technological assumption for long-term CASPR compliance.

Mr. Carmichael testified that NIPSCO has a proven track record of navigating compliance and assuring that associated timing and costs were ultimately warranted to achieve compliance. With regards to consideration of other scenarios in the 2018 IRP, he also briefly explained that the ICC requested NIPSCO to perform an analysis with its own set of assumptions—scenarios that included no carbon costs, reduced future environmental capital costs, flat coal pricing, and a high natural gas price curve. The output presented at IRP stakeholder meetings showed that, even under the ICC's market scenario with no new environmental capital for the coal plants, retirement of coal as early as possible still remained the lowest cost option. Mr. Carmichael also noted that NIPSCO is required to submit another IRP within the next three years (i.e., prior to the proposed 2023 retirement of the Schahfer coal-fired units) and that this IRP will incorporate the most current information and projections on environmental costs and timing.

Mr. Carmichael also responded to three issues that Mr. Nasi seemed to misunderstand in Mr. Carmichael's direct testimony. First, regarding the alleged mismatch for ELG Rule compliance costs, he clarified that the $170 million estimate from page 13 of his direct testimony is NIPSCO's initial ELG Rule compliance estimate for Schahfer Units 14 and 15. He explained that, looking at page 12 of that testimony, it stated that Michigan City Unit 12 would not need to incur ELG Rule compliance costs, because it has a dry FGD system installed, and this was also addressing Schahfer Units 14 and 15. The $440 million estimate provided in response to discovery, which was included in Nasi's Attachment No. MJN-2, was an estimate for Schahfer Units 14 and 15, as well as Schahfer Units 17 and 18. Second, Mr. Carmichael stated that Mr. Nasi's criticism of NIPSCO not advocating for ELG Rule changes that go beyond bottom ash transport water and FGD wastewater shows that he misunderstands NIPSCO operations and/or the ELG Rule. Mr. Carmichael outlined why it would be nonsensical for NIPSCO to waste time and resources advocating for additional ELG Rule changes when such changes would have no potential benefit for NIPSCO and its customers. Third, regarding Mr. Nasi's criticism of NIPSCO's inclusion and accuracy of capital and O&M costs and inclusion of costs that will be incurred regardless of whether the units continue to operate to justify retirement decisions, Mr. Carmichael pointed to Mr. Augustine's rebuttal testimony, which explained that NIPSCO evaluated a portfolio with no new environmental capital for all coal units and found that retiring coal early provided significant savings to customers even in this scenario.

H. Mr. Campbell. Mr. Campbell responded to Industrial Group witness Dauphinais' testimony about the Rate 831 tariff language regarding curtailment notification and US Steel witness Thornton's testimony related to Rate 831 customer qualification for Auction Revenue Rights ("ARRs")/ Financial Transmission Rights ("FTRs"), recommended phase in period for Rate 831 implementation, and MISO billing disputes.

Mr. Campbell testified that while NIPSCO does not oppose the recommendation by Mr. Dauphinais for a two-hour curtailment notice for Rate 831 customers, consistent with current practices, NIPSCO will add 30 minutes to the LMR notification time to allow for the communication of any MISO curtailment event.

In response to Mr. Thornton, Mr. Campbell testified that Rate 831 customers will not qualify for ARRs/FTRs. He explained that because MISO requires that an entity be registered as a Market Participant to hold FTRs or ARRs, NIPSCO, acting as the MISO Market Participant, will register Rate 831 customers electing Tier 3 service as Asset Owners. He explained that the MISO Tariff and Business Practices Manuals explain what actions Asset Owners are qualified to perform. He stated that MISO Market Participants are the only entities allowed to procure FTRs with MISO because of the additional credit requirements to participate in the FTR market but that MISO Market Participants may act as agents and procure FTRs on behalf of other parties. He stated that under Rate 831, NIPSCO will not act as an agent to procure FTRs on behalf of the Rate 831 Tier 3 Customer but that customers are free to contract with other third-party MISO Market Participants to obtain FTRs. He indicated that any settlements will be handled outside of the MISO settlement process between Rate 831 customers and the third-party MISO Market Participant. He stated that Mr. Thornton characterized allocated ARRs/FTRs as a benefit, but they can also represent a cost and that if Rate 831 customers are allocated ARRs/FTRs, they should also be allocated their portion of any charges associated with the ongoing investment in the transmission system.

Mr. Campbell disagreed with Mr. Thornton's proposal for a phase-in period for Rate 831 implementation. He explained that NIPSCO is proposing that any qualifying customer that is unable to take service under Rate 831 be placed on either proposed Rate 832 or Rate 833 with the requirement that the customer also maintain any historical curtailable service (MISO LMR registration) under prior Rider 775 through the end of the current MISO 2019/2020 Planning Year. He stated that, alternatively, for customers that are intending to take Tier 3 service under Rate 831, customers can choose to take service under Tier 2 until they are ready to transition to Tier 3 service. He noted that this optionality is already present in Rate 831 where customers can change their elections between Tier 2 and Tier 3 quarterly (commensurate with MISO model update cycle).

Mr. Campbell testified that NIPSCO has identified a process for assisting customers in addressing their MISO LMR exposure when activating their Rate 831 service. He explained that NIPSCO is proposing that customers be able to purchase any ZRCs associated with the customer's existing firm load that is transferring to Rate 831 above their Tier 1 firm election to afford customers the benefit of existing firm load that has already cleared the MISO PRA.

In addition, to assist customers with procuring MISO Zone 6 ZRCs from third-party suppliers during the 2019/2020 planning year, NIPSCO is offering to conduct a one-time RFP for intra-year MISO Zone 6 ZRCs prior to the implementation date for the benefit of Rate 831

customers to assist them in firming up their LMR obligations should they so desire when activating their Rate 831 service.

Mr. Campbell disagreed with Mr. Thornton's recommendation that during the proposed phase-in period, NIPSCO should work with its Rate 831 eligible customers to develop a model agreement that includes acceptable terms and conditions for customer-procured capacity and/or energy. He stated there are many ways to construct bilateral arrangements. He noted that an ISDA Master Agreement or EEI Master Contract are industry tools that can help form those agreements, especially in instances where there is a potential for multiple reoccurring transactions. He explained that standalone contracts are also employed, but they can have many of the elements referenced in the ISDA or EEI. He stated that based on NIPSCO's understanding, contracts in the broader market, while similarly structured, have certain provisions that are unique per counterparty requirements and additional provisions that are unique because of customer specific requirements. He indicated that recognizing that there is the potential for standard and non-standard agreements for customer-procured capacity and/or energy, NIPSCO is committed to working with the customer and the customer's identified third party in outlining the terms associated with any potential agreement incidental to Rate 831 service. He stated that in general, such agreements between NIPSCO, customer, and third party for capacity and/or energy will need to be a three-party agreement between NIPSCO, customer, and customer's third-party supplier, and at a minimum such agreement will need to contain provisions that: (1) identify NIPSCO as the Market Participant for the retail customer at MISO; (2) reference-NIPSCO's market based rate authority with FERC; (3) clearly state the Rate 831 customer remains a retail customer of NIPSCO; (4) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations); and (5) incorporates relevant provisions from NIPSCO's Rate 831 schedule.

He testified that NIPSCO also understands that certain terms such as, but not limited to, pricing may need to be treated as confidential and may be limited from view from certain NIPSCO personnel and, further, may be subject to a non-disclosure agreement. He stated that while NIPSCO does not believe a model agreement is necessary or prudent given the unique nature of potential capacity and energy transactions, NIPSCO believes the details outlined above are responsive to the concerns outlined by Mr. Thornton.

Mr. Campbell disagreed with Mr. Thornton's request that NIPSCO modify the language on billing disputes by adding specific dispute resolution provisions, which would define the rights and obligations of NIPSCO and the industrial customer, and include specific remedies. He stated that the dispute process is adequately defined in proposed Rate 831. He described that, in general, the hierarchy as defined within Rate 831 allows an Asset Owner to file the dispute with MISO, while keeping NIPSCO informed. If the dispute is denied and the customer wants to pursue it further, the customer needs to request NIPSCO to file an Alternative Dispute Resolution ("ADR") on its behalf with MISO. He noted that if the customer is unsatisfied with MISO's decision in the ADR, it can pursue a complaint with FERC.

I. Mr. Ranalletta. Mr. Ranalletta disagreed with Mr. Gorman that a contingency factor is not a known and measurable cost and therefore not appropriate for including in rates. He testified that use of a contingency factor in any major construction or demolition

project is well accepted in the industry, the amount selected here is well supported, and it is sufficiently certain for purposes of including expected demolition costs in Mr. Spanos' calculation of depreciation accrual rates. He stated that estimates of demolition costs of NIPSCO's generation plants are prepared with the intent of accurately representing what contractors would bid to abate, remediate, and demolish the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known decommissioning tasks under ideal conditions. He stated that he included a 20% contingency factor in his estimates. He explained that in addition to the known tasks under ideal conditions, contingency is added to account for unknown, but reasonably expected to be incurred, costs. He indicated that the application of contingency is a common and prudent practice in the construction and demolition industries, and it is included in order to recognize the probability of increases in cost due to these unknown events. Finally, he noted that contingency is a cost that is typically included by owners throughout all stages of planning and execution of the project.

J. Mr. Spanos. Mr. Spanos first responded generally to the criticism by other parties regarding the service lives of generating plant. He testified that other parties are misusing the phrase "accelerated depreciation." He explained that NIPSCO's proposed depreciation rates based upon the current estimated useful lives of the generating plants is not a form of accelerated depreciation. He reiterated the service lives used in his study and pointed out that other parties argued not to update the service lives from prior studies or inherent in existing rates or generally not to retire the plants as planned. He testified that in his experience, it is more common for assets such as power plants to be retired before they have been fully depreciated than such assets becoming depreciated before being removed from service. Given this reality, he explained that depreciation rates should be set as accurately as possible but that erring on the higher side for depreciation rates is preferable to erring on the lower side. The likelihood and the risks of adverse effects on both the utility and customers are greater if depreciation is underestimated.

With respect to Mr. Garrett's proposal to reject the Equal Life Group procedure, Mr. Spanos testified that Equal Life Group has been used in Indiana for many years. He quoted the 43526 Order, where the Commission stated, "We consider the debate between [Equal Life Group] and [Average Life Group] to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the [Equal Life Group] procedure." P. 51. He then summarized the history of the use of the Equal Life Group in Indiana.

Mr. Spanos also responded to Mr. Garrett's proposal to remove escalation from decommissioning costs. He again cited to NIPSCO's most recent litigated case and to a 2004 rate case in Cause No. 42359. He testified that in both cases, it was affirmed that decommissioning costs should be escalated to the future time at which the facilities would be retired.

With respect to contingency, Mr. Spanos testified that the use of contingency is also accepted by this Commission and that, indeed, Mr. Gorman's firm had previously proposed to remove contingency for NIPSCO in Cause No. 43526 and was rejected.

Mr. Spanos also responded to the nine mass property accounts for which Mr. Garrett had proposed service life adjustments. Mr. Spanos noted that his depreciation study recommended an increase to the average service life from both current depreciation rates and the estimate from the previous depreciation study. He explained that Mr. Garrett's proposals are to increase the service

lives even further. He testified that Mr. Garrett's adjustments relied too much on mathematical curve fitting and too little on the use of informed judgment. He gave examples where Mr. Garrett's approach resulted in estimated survival years beyond what should be considered reasonable. Finally, he noted that all of Mr. Garrett's adjustments resulted from an error in constructing his charts in Excel, which shifted the smooth survivor curves to the right in each graph.

K. Mr. McCuen. Mr. McCuen responded to the parties' testimony related to excess ADIT. He stated that all witnesses agree that the IRS has mandated that these excess ADIT be passed back to customers using ARAM and that all witnesses understand that the unprotected excess ADIT can be passed back to customers over any reasonable period of time. He testified that he has proposed using ARAM, Mr. Blakley proposed a five-year amortization period, and Mr. Gorman proposed a ten-year amortization period. Mr. McCuen supported his proposal using ARAM based on the Commission's June 1, 1987 Interim Order in Cause No. 38194 and the Report of the Executive Committee filed in that Cause on April 15, 1987, concluding that all excess deferred taxes should be passed back using ARAM, specifically stating that "protected" deferred taxes are those that relate to depreciation method and life of public utility property and the "unprotected" portion includes the remaining balance of excess deferred taxes. The Report found that excess deferred tax reserves existing on the books of utilities at whatever point in time the utility reduces its tax rate in compliance with the Tax Reform Act of 1986, should be returned to the ratepayers utilizing ARAM. Mr. McCuen stated that while the Executive Committee chose not to differentiate, he believes the portion of the unprotected items related to property (repairs, capitalized overheads, and mixed service costs) should appropriately follow the ARAM flow back to customers, and the non-property related excess deferred taxes may have a more appropriate shorter flowback period depending on the underlying cause of the temporary difference giving rise to the deferred tax. Mr. McCuen proposed a ten-year amortization period for these types of items.

Mr. McCuen believes the shorter period offered by Mr. Blakley and Mr. Gorman is not appropriate because: (1) investment decisions have been made taking into account the cash flow for the payment of taxes, whether the payment is to the federal government or a return to the customer, the payments should be made over the same period of time so as not to invalidate the economics underlying those investment decisions which have already been made; (2) the flow-back of excess deferred taxes should be done ratably over the life of the asset giving rise to the deferred taxes to avoid inter-generational inequity between customers today and those customers in the future that will continue to pay for the asset; and (3) a rapid flowback of excess deferred taxes will negatively impact NIPSCO's cost of capital that raises the cost to customers, the WACC will increase at a faster rate with a rapid flowback of the excess ADIT, and the negative cash flow implications for NIPSCO may result in degradation of credit ratings, which will increase financing costs of investments and ultimately the WACC.

Mr. McCuen explained what the pass back would look like had the TCJA not been enacted. He stated that when looking at the unprotected property related items, such as repairs and mixed service deduction, the deferred taxes reverse over the life of the assets as they are depreciated. The assets that these deductions relate to are typically long-lived utility assets with book lives over 40 years. He stated that the deferred taxes are purely the result of timing differences as the tax deduction has been taken more quickly than the expense is incurred for regulatory purposes. He explained that assuming a capital asset was installed at the beginning of Year 1 with a 40-year life but which qualified for the repairs deduction, at the end of Year 1, the entire investment would be

deducted for tax purposes, but for regulatory purposes only one year of depreciation expense would be recorded. He stated that the deferred tax this situation creates will reverse over the remaining 39 years, as depreciation expense is recorded for regulatory purposes. For these reasons, NIPSCO believes amortization of the excess deferred taxes over the remaining life of the assets is the most prudent approach for its customers.

Mr. McCuen testified ARAM provides tax benefits to ratepayers smoothly over the life of the investment. In contrast, flowing it through over a five-year period front loads the benefit. Returning to his example of the single repairs deduction, under Mr. Blakley's proposal, for the next five years rates would be held artificially low as the excess deferred taxes are amortized over his abbreviated timeframe. Then there would be an immediate spike as the abbreviated amortization ends, and the spike would be exacerbated by an increase in the WACC caused by the deferred taxes having been flowed back entirely. He explained using the five-year amortization period means ratepayers will be charged more after that period because the deferred taxes will not be an offset to tax expense and the WACC will be higher. He testified that NIPSCO believes that using ARAM and providing the tax benefits to ratepayers smoothly over the life of the investment is the most prudent alternative.

Mr. McCuen explained how the pass back of excess deferred taxes impacts inter-generational equality. He stated that the normalization concept prevents the inter-generational inequity that can occur when the flow-through method is used. If NIPSCO uses an immediate or faster flow-through method, current customers receive the entire refund and disproportionally benefit. Returning to his example of the single repairs deduction, under Mr. Blakley's proposal, customers during the first five years see 100% of the benefit from the TCJA, whereas the customers over the remainder of asset's life see none of the benefit although the asset giving rise to the benefit will serve all of them. The WACC is also inequitable for those later customers. He stated that the entirety of the zero-cost excess deferred taxes will have already been returned over the first five years, meaning a higher WACC for the remainder of the life of the asset giving rise to the benefit. Mr. Blakley's and Mr. Gorman's approach is the equivalent of paying the lowest interest loans in the capital structure first rather than the higher interest loans. In this scenario, future customers are unfairly penalized because they may not receive any refund, yet pay for the cost of the utility asset over its remaining useful life. He testified that normalization ensures that tax benefits are spread to all customers who benefit from NIPSCO's long-life assets, not just current customers. He testified that NIPSCO believes that the normalization concept should be applied to unprotected property, and the pass back of these excess deferred taxes should use ARAM.

Mr. McCuen explained how a normalization approach to the return of unprotected property related items impacts the originally anticipated payment to the government. He testified that under a policy of normalization for the return of excess deferred taxes, NIPSCO would be required to pay the money no longer owed to the government to its ratepayers instead, but in approximately the same time pattern as NIPSCO originally expected to pay it to the government.

Mr. McCuen disagreed with Mr. Blakley that ADIT represents a "loan" from ratepayers to the utility because although Mr. Blakely correctly identifies how ADIT is created, ADIT is really an interest-free loan from the U.S. Government. Mr. McCuen cited to a FERC Order finding no reasonable basis for concluding that customers actually provide a loan to their utility. He added that the ARM methodology used by NIPSCO is required by the IRS.

Mr. McCuen testified NIPSCO is currently amortizing the regulatory liability associated with excess deferred taxes using ARAM. He stated this regulatory liability includes excess from pre-TCJA and amounts generated from TCJA. Mr. McCuen reiterated that NIPSCO has continued to follow the guidance provided by the Commission in its June 1, 1987 Interim Order. He explained that the Commission has always approved this approach, most recently in its 44688 Rate Case Order, and this is the proper accounting and regulatory treatment until a new order is issued. He also noted that the filed rate doctrine and prohibition against retroactive ratemaking bar NIPSCO from charging a rate other than the rate properly filed with the Commission, and similarly bar the retroactive imposition of a rate change for service already provided.

L. Mr. Rea. Mr. Rea testified that the ROE recommendations of OUCC witness Woolridge and Industrial Group witness Gorman should be rejected by the Commission. Specifically, Dr. Woolridge recommended that NIPSCO's ROE be set at 8.75% but further proposed that in recognition of the practice of gradualism, a 9.25% ROE would be more appropriate. Mr. Gorman recommended an ROE of 9.35%. In his rebuttal testimony, Mr. Rea demonstrated that the ROE recommendations of Dr. Woolridge and Mr. Gorman would not allow NIPSCO the opportunity to earn a fair return as compared to other electric utility companies. He stated that if these ROE recommendations were adopted, it would send a message to the financial community that Indiana's regulatory climate was not fully supportive of maintaining financially sound utilities, which could have negative implications from a capital attraction standpoint.

Mr. Rea testified that by ignoring the authorized returns of other electric utility companies of comparable risk, Dr. Woolridge and Mr. Gorman have failed to recognize the fair return standards established in the Hope and Bluefield cases. Mr. Rea further stated Dr. Woolridge and Mr. Gorman failed to adequately recognize that U.S. capital market conditions have recently been anomalous and that the Federal Reserve's recent monetary policy interventions have played a contributory role in driving interest rates to all-time lows and the stock market to its all-time high.

Mr. Rea testified that the failure of Dr. Woolridge and Mr. Gorman to evaluate a broader group of non-rate-regulated companies with comparable risks, and which provides useful perspective on the competitive market result, ultimately causes their cost of equity recommendations to be unreliable. He stated that the manner in which they have applied the DCF, CAPM, and Risk Premium models suffer from a number of infirmities. He also stated that their failure to evaluate the expected earned returns of companies with comparable risks results in ROE recommendations that do not adequately recognize the Comparable Earnings standard established in Hope and Bluefield.

Mr. Rea further testified that the recommendations of Dr. Woolridge and Mr. Gorman to: (1) reduce NIPSCO's authorized ROE on the basis of NIPSCO's equity capitalization layer; (2) reduce NIPSCO's authorized ROE due to the implementation of NIPSCO's TDSIC program and other regulatory mechanisms; and (3) deny a return on NiSource's stock issuance flotation costs, should all be unequivocally rejected. He summarized that after reviewing the testimony and analyses of Dr. Woolridge and Mr. Gorman and revisiting his original cost of equity evaluation, he concluded that NIPSCO's cost of equity remains in the range of 10.55% to 11.05%, and that the Commission should adopt a cost of equity at the midpoint of this range, or 10.80%.

Mr. Rea sponsored Attachment 15-R-B, Schedule 2 – Updated, presenting NIPSCO's capital structure as of December 31, 2019, as follows:

Projected Capital Structure as of December 31, 2019

	Balance (000)	% of Total	Cost	WACC
Common Equity	$2,864,884,714	47.85%	10.80%	5.17%
Long-Term Debt	2,151,351,378	35.93%	4.97%	1.79%
Customer Deposits	71,453,491	1.19%	5.15%	0.06%
Deferred Income Taxes	1,266,429,454	21.15%	0.00%	0.00%
Post-Retirement Liability	66,142,914	1.11%	0.00%	0.00%
Prepaid Pension Asset	(435,272,223)	-7.27%	0.00%	0.00%
Post-1970 ITC	2,014,831	0.03%	8.30%	0.00%
Totals	$5,987,004,559	100.00%		7.02%

M. Ms. Strauss. Ms. Strauss addressed proposed bill counts and kWh usage for residential customers, including weather normalization, sponsored by OUCC witness Novak and that clarified the support used as the basis for the derivation of proposed billing determinants sponsored by NIPSCO witness Westerhausen. Ms. Strauss was critical of Mr. Novak's proposed bill counts, contending that they had employed unreasonably high growth rates and as a result producing a residential customer bill count that was excessive. She explained that NIPSCO recommends considering other factors in addition to historic growth levels when forecasting customer counts and reiterated that NIPSCO's method for forecasting residential bill counts relies on market intelligence from the New Business Team and is cross checked by running a regression analysis, which shows that local housing starts are a strong predictor of new residential customers.

Ms. Strauss testified that the only similarity between the weather normalization she sponsored and that discussed by OUCC witness Novak was his proposal to adjust only residential and commercial customer classes for weather due to the correlation between their energy usage and weather. She explained that Mr. Novak's proposed weather normalization adjustment had been developed outside of the regression modeling used to produce NIPSCO's forecasted usage, and thus could not be applied to NIPSCO's forecast. She testified that the OUCC recommendation of 3,616,043,140 kWh for the residential customer class for 2019 included a weather normalization adjustment of 158,919,910 kWh (almost 4.4% of the total) and a growth adjustment of 172,942,640 kWh (more than 4.7% of the total) and that the forecast was unreasonably high. She noted that Mr. Novak's projected Forward Test Year residential usage per customer was above NIPSCO's historic annual usage per customer even when that annual usage per customer is calculated using the OUCC excessive bill count. She testified that NIPSCO's forecasted 2019 residential usage of 8,286 kWh per year is below the actual 2016 usage and consistent with the trend of decreasing usage per customer observed from 2012 through 2016. She concluded that NIPSCO's demand forecast is based upon econometric analyses and statistically significant regression results, is more reasonable and reflective of actual experience on NIPSCO's system, and should be approved.

N. Mr. Rimal. In rebuttal, Mr. Rimal discussed the changes to some of the special studies used for cost allocation that he had conducted for his direct testimony. He stated these changes are driven by three primary factors: (1) the migration of a sixth customer into Rate 831; (2) the assumption that customers that would have been moved to the new Rate 830 will remain with their original rate schedules (now Rates 832 and 833); and (3) revisions to the test year projected billing units associated with Rates 721, 723, 724, and 726 to reflect customers that have migrated between rate schedules.

O. Dr. Gaske. In rebuttal, Dr. Gaske responded to issues raised by OUCC witness Watkins, NLMK witness Lahtinen, Industrial Group witness Phillips, US Steel witness Georgis, CAC witness Wallach, Sierra Club witness Allison, and Walmart witness Chriss. He also updated the ACOSS and addressed associated rate design and bill impacts for changes in NIPSCO's revenue requirement.

Dr. Gaske noted that Mr. Phillips and Mr. Lahtinen agreed with the 4CP method for the allocation of production costs because NIPSCO is a strong summer-peaking utility and Mr. Lahtinen asserted that this approach will help combat bypass by the large customers. In response to Mr. Watkins recommendation that either the BIP, P&A, or 12CP methods would result in a reasonable allocation of NIPSCO's demand-related production costs, Dr. Gaske testified that these methods would allocate greater costs to the new Rate 831 industrial class that will consist of customers who will purchase only a minor portion of their power from NIPSCO. He testified that he used the 4CP method for NIPSCO because in recent years, the system peaks in 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. He disagreed with Mr. Watkins that the 4CP does not recognize the investment or operational characteristics of NIPSCO's generation portfolio as it allocates the total generation plant investment based on a few peak hours of the year. He also showed that Mr. Watkins incorrectly assumed that NIPSCO's baseload facilities have higher capacity costs than intermediate or peaking facilities. This incorrect assumption that baseload plant achieves lower energy costs by incurring higher capacity costs led Mr. Watkins to conclude that the BIP or P&A methods are more appropriate because he assumed that they recognize the fact that the baseload generation resources are utilized at a very high capacity factor to meet the energy needs throughout the year. Dr. Gaske explained that once installed, any generation asset may be available for dispatch at any time. He stated that while Mr. Watkins is correct that utilities typically consider a tradeoff between capacity costs and energy costs when they first construct a plant, circumstances change and the relative costs of fuel and the efficiencies of different types of capacity can change significantly over time. He stated that the assumption that NIPSCO incurred higher capacity costs in order to achieve lower energy costs for its baseload units is not correct.

Dr. Gaske also disagreed with Mr. Watkins' criticism of the FERC tests to determine the reasonableness of 4CP allocator noting that his criticism is based solely on the fact that the tests were developed by FERC. He stated that the FERC tests are a commonly used method for analyzing system load characteristics and determining whether a utility has monthly peak periods that can be distinguished from off-peak periods and that establishing the extent to which such a distinction exists provides a basis for determining the time periods which are most relevant for production and transmission capacity cost incurrence.

Dr. Gaske also responded to Mr. Watkins testimony that the 4CP peak hours occurred during mid-afternoon summer hours when certain commercial heating (Rates 720 and 722) and the lighting (Rates 750 and 760) services are not using any electricity and his criticism of the 4CP method because it does not allocate any generation capacity costs to those services. He stated that to the extent that these heating and lighting services are off-peak and do not cause or contribute to the need to construct additional generating plant, it is not unreasonable that they should receive little or no allocation of generating plant costs. He noted that the commercial heating services are small, ancillary services that are used by customers who take their primary electric service under other rates that do have an allocation of generating plant costs and that the total bills paid by these customers are designed to cover the costs of providing their services.

Dr. Gaske testified that Mr. Watkins concluded that the 12CP method is reasonable for allocating transmission costs. He testified that although Mr. Georgis' proposal to sub-functionalize the transmission facilities might be more accurate, all ratemaking involves some degree of averaging of costs of different facilities and customer characteristics. Thus, this issue basically reduces to a question of how far to go in de-averaging rates and recognizing individual differences. In Dr. Gaske's opinion, the method proposed by NIPSCO is reasonable, and he did not propose to change that method in his updated, rebuttal calculations.

In response to Mr. Allison's argument that minimum system distribution costs are not clearly a function of the number of customers because if a customer has zero demand, then there is no need to build any distribution infrastructure, Dr. Gaske testified that the minimum system analyses used by Mr. Rimal are based on the assumption that there is a minimum-sized distribution system required to be capable of serving minimum requirements of customers. He stated that this minimum system cost is dependent primarily on the number and location of customers, not on the peak demand the customers place on the system. He responded that the zero-demand assumption that Mr. Allison invokes is relevant under the "zero-intercept" or the "minimum-intercept" method, which seeks to identify the portion of the plant that is related to a hypothetical no load situation, but it is not relevant for the minimum system method that is used in Mr. Rimal's study.

In response to Mr. Allison's argument that if a new customer is added to an already populated area, there are no additional secondary distribution costs unless that customer increases the peak demand on the distribution system and, therefore, the cost is driven by demand and not the number of customers, Dr. Gaske testified that does not mean that the entire distribution system cost should be classified as being demand-driven. He stated that a portion of the distribution system that was existing before a customer is added is required to serve the minimum requirements of the customers and their geographic dispersion. He explained that the whole point of conducting a minimum system analysis is to calculate the portion of the distribution system that does not vary by demand because a portion of the distribution costs are incurred regardless of the peak demand of the customers. He noted that increases or decreases in demand do not result in proportionate increases or decreases in the number of poles and miles of conductors required to distribute electricity. He explained that a portion of the distribution system costs are classified as customer-related because the distribution system exists to deliver electricity to hundreds of thousands of customers who are widely dispersed. He said that a significant portion of those costs are totally unrelated to the peak demand and, thus, should not be allocated based on demand. He noted that Mr. Allison appears to agree that minimum system costs could reasonably be allocated to classes

based on the number of customers, but Mr. Allison more strongly objects to inclusion of those costs in the customer charge for rate design purposes.

Dr. Gaske disagreed with Mr. Wallach's assertion that the minimum secondary distribution cost per customer is overstated by a minimum system study. He stated that distribution system costs are incurred to move electricity from generation and transmission facilities to individual customers that are distributed geographically throughout the NIPSCO service territory. He noted that Mr. Wallach is correct that some portion of the distribution system costs vary with demand, which is why the ACOSS classifies a portion of the costs as demand-related, but it is incorrect to assume that all distribution system costs are demand-related.

In response to Mr. Wallach's statement that distribution equipment that carries zero load can serve an infinite number of customers with zero load, Dr. Gaske agreed that an infinite number of customers could be served by the NIPSCO distribution system if each customer has a demand approaching zero. However, NIPSCO is allocating the costs to the customers that are actually served by its distribution system. He stated again that the minimum system method is based on the premise that a minimum size distribution system is required to deliver electricity to the geographically dispersed customers that are actually on the NIPSCO system, and the costs of this minimum system is unrelated to either peak demands or total energy usage. He noted that although the minimum system costs per customer would be lower for a utility that serves a more densely populated territory, it is still reasonable for the customers to share those costs equally because a large portion of distribution system costs are related to reaching the numerous, geographically dispersed customers, and those minimum system costs are unrelated to peak demand.

Dr. Gaske disagreed with Mr. Wallach's claim that all line transformer costs had been classified as customer-related and his argument that a portion of these costs should be classified as demand-related. Dr. Gaske stated that line transformers are at the intersection of the distribution system and the customer premises and, like meters and services, are designed for the specific customer or customers at a location. For that reason, these costs are largely related to the number of customers. He stated that, more importantly, the line transformer costs (Account 368) are not allocated based on a simple allocation by number of customers but instead, a weighted customer allocation was developed based on the types of transformers and costs used to serve each class. This weighted approach allocates 4.5 times as much per customer to commercial customers than residential customers, which implicitly reflects the greater demand and more accurately reflects the higher cost of transformers for commercial customers. He testified that approximately 96% of these line transformer costs are allocated to the residential and small commercial classes, which do not have demand meters. Thus, once allocated to the classes based on their different weighted costs per customer, it is most appropriate to recover these costs in the customer charge because the costs are fixed regardless of a customer's energy use.

Dr. Gaske disagreed with Mr. Georgis' recommendation that transmission-related revenue in Account 456 should be allocated to the various rate classes in the same manner that transmission costs are allocated (i.e., the 12CP method). He testified that he used the amount of revenue margin (i.e., revenue excluding fuel costs) for each class as an allocator to allocate and credit Account 456 transmission-related revenues to the various classes. He explained that these revenue credits are used to offset the fixed costs incurred by all classes on an equal basis relative to their contributions to the revenue margin. He stated that although the approach proposed by Mr. Georgis is not

unreasonable, it is also reasonable to continue to treat the transmission revenues as a general source of funds available to offset the overall costs of serving all classes on a pro rata basis.

Dr. Gaske disagreed with the rate mitigation strategies proposed by Mr. Wallach, Mr. Watkins, and Mr. Chriss. He testified that with the possible exception of Mr. Chriss, each of these witnesses appears to agree that increasing all rate classes except Rate 831 by an equal percentage is reasonable. He noted that, as discussed by NIPSCO witness Kelly, the proposals to allocate either more or less costs to Rate 831 would not be consistent with the balance between competing interests and competitive pressures that NIPSCO is trying to achieve in its proposed industrial service restructuring, cost allocation, and mitigation. Importantly, he noted that the proposed Rate 831 revenue requirement is not a discounted rate but instead, the Rate 831 revenue requirement is set equal to the fully allocated cost of service.

In response to the objections of Mr. Wallach, Mr. Watkins, and Mr. Allison to the implementation of an SFV rate design concept, Dr. Gaske testified that although an SFV rate design would provide better price signals for efficient usage, he is not proposing an SFV price structure for NIPSCO's residential and commercial customers at this time. Instead, a substantial amount of fixed costs would continue to be recovered in the energy charge and the marginal price of consumption generally will exceed the marginal cost of production by a large amount. He testified that while he disagrees with their assertions and interpretations concerning the theory of efficient pricing, in reality NIPSCO's proposed rate structure would recover only a small fraction of residential and small general service fixed costs in the customer charge and as a result, many of their theoretical arguments are misdirected.

Dr. Gaske disagreed with the arguments that the energy rate should be based on long-run marginal costs and as a result, it is appropriate to recover demand-related costs from residential customers in the variable energy rate in proportion to their energy use. He testified that fixed, demand-related production and transmission costs are typically driven by the coincident peak demand while demand-related distribution costs are generally driven by the non-coincident peak demand on different parts of the system. He stated NIPSCO incurs these costs to meet peak load; therefore, they are not based on the total amount of kWh a given customer consumes. He noted that customer coincident and non-coincident peak loads are a significant driver of the costs of NIPSCO's distribution system.

Dr. Gaske also disagreed with claims that recovering a small portion of demand-related costs in the customer charge and less than 100% of such costs in the energy rate would result in cost subsidization within the residential class and would dampen energy price signals to consumers for controlling bills through conservation, EE investments, or distributed renewable generation. He testified that the production and delivery of electricity consists of both fixed costs and variable costs. He explained that when a rate structure recovers fixed costs in variable energy charges, as Mr. Wallach, Mr. Watkins, and Mr. Allison recommend, the rate structure overstates the marginal cost of electricity and discourages consumption that would be efficient because the marginal benefit of consuming additional units of electricity exceeds the marginal cost of the energy required to produce that electricity. He stated these witnesses' concepts of conservation and efficiency appear to be narrowly focused on attempting to discourage electricity use and encourage consumption of alternative resources, but electricity use provides enormous benefits to consumers

and the community, and consumers require proper price signals as to the marginal cost of electricity to make decisions that improve the welfare of themselves and the community.

In response to Mr. Watkins' claims that the price signal that results from SFV pricing is meant to promote additional consumption, Dr. Gaske testified that it is more accurate to say that this type of rate design is meant to promote efficient consumption by allowing alternative energy sources to compete on the basis of their marginal fuel cost without the distortion of trying to collect fixed costs through a variable energy charge. Regarding FERC Order No. 636, Dr. Gaske indicated that FERC placed all of the fixed costs in a demand charge so that recovery of fixed costs in the volumetric charge would not distort the price signals in the commodity cost of energy and thereby improve competitive efficiency in the market. He stated that for customers with demand meters, NIPSCO is generally proposing to recover the demand-related fixed costs in a demand charge, and the customer-related fixed costs in a customer charge so that the energy charge is close to the utility's variable cost of fuel and energy thus promoting efficiency because it charges customers based on the costs they cause the utility to incur. Dr. Gaske disagreed with Mr. Watkins' discussion on theoretical pricing in competitive markets noting that Mr. Watkins neglects the fact that many competitive industries use multi-part rates to properly reflect costs and dimensions of service.

Dr. Gaske presented updated cost of service and rate design schedules assuming separate small industrial rates are retained for low load factor and high load factor service. He stated that in these schedules, proposed Rate 832 comprises those industrial customers currently taking service under Rate 732 that will not be moving to the proposed large industrial Rate 831, and proposed Rate 833 is comprised of customers currently taking service under Rate 733 that will not be moving to proposed Rate 831. He listed all the changes that were incorporated into the updated ACOSS and rate design as: (1) an update to the revenue requirements; (2) the assumption that customers that would have been moved to the new Rate 830 will remain with their original rate schedules (832 and 833); (3) the migration of a sixth customer into Rate 831 with a reduction in that customer's expected 4CP demand and billing unit; and (4) revisions to the test year projected billing units associated with Rates 721, 723, 724, and 726 to correctly reflect customers that have migrated between rate schedules. He concluded that in general, these changes had a *de minimis* effect on the rates that NIPSCO is proposing for the various classes.

P. Mr. Westerhausen. In response to Industrial Group witness Phillips' concerns with NIPSCO's proposed Rate 830, Mr. Westerhausen testified that NIPSCO is willing to develop two separate rates, both a load factor rate and a high load factor rate for those current customers receiving service on Rate 732 and Rate 733 not opting, or eligible, for Rate 831 service. He stated that to prevent an unintended adverse impact on NIPSCO's low load factor customers, NIPSCO is willing to continue a Rate 732 low load factor service (now proposed Rate 832) and a Rate 733 high load factor service (now proposed Rate 833). He explained that these new rates will include the Back-Up, Maintenance, and Temporary Service that was proposed in Rate 830. He stated that Appendix A has been revised to reflect new Rates 832 and 833. He testified that in its compliance filing to implement Step 1 rates, NIPSCO will update its Series 800 Tariff to address the removal of Rate 830 and the addition of Rates 832 and 833.

Mr. Westerhausen also testified that a transition service that expires on May 31, 2020, has been added to both Rate 832 and Rate 833 for customers that intend to move to proposed Rate 831 but will not be ready when the new rate schedules go into effect. He explained that these customers

will be required to maintain their historical interruptible capacity through the current MISO Planning Year and that the maximum capacity contract limit of 25,000 kW will not go into effect until June 1, 2020. He stated that language from NIPSCO's current Rider 775 for Character of Service, Curtailment, and Interruption limits, Interruptions, Energy Charges and Customer's Failure to Comply with Requested Interruptions or Curtailment has also been added to both rates.

Mr. Westerhausen responded to US Steel witness Thornton's concerns that: (1) although most of the riders are straightforward with respect to calculation and application, there are concerns about possible cost shifting depending on customers' Tier 1, Tier 2, and Tier 3 firm capacity elections; (2) it is not clear whether the energy and demand tracker allocators will be trued up once the large industrial customers have made final firm capacity elections; and (3) truing up tracker allocators is necessary to avoid possible inter-class subsidies and over-collection of costs. Mr. Westerhausen testified that: (1) NIPSCO will true up the energy and demand tracker allocators with the final Tier 1, 2, and 3 contracts; and (2) there were no changes to NIPSCO's proposal for the allocation of its various trackers to the different tiers of service within Rate 831 – the methodology is the same as what NIPSCO presented in its case-in-chief, but the proposed tracker allocations were updated to reflect the rebuttal ACOSS, which includes the rebuttal revenue requirement and the migration of one additional customer to proposed Rate 831.

Mr. Westerhausen addressed an update to the Rate 831 billing determinants. He stated one additional large customer is being migrated from proposed Rate 830 to proposed Rate 831, resulting in an additional ten MW of Rate 831 Firm Demand, 86,597,913 kWh Tier 1 energy, and 63,271,988 kWh Tier 2/3 energy. He explained that Tier 1 energy was calculated by using 2017 actual 30 minute kW meter readings and by allocating the lessor of ten MW or their actual demand into Tier 1 energy, and the remaining if their actual demand was greater than ten MW into Tier 2/3 energy. He said the 2017 monthly total energy was then compared to the 2019 forecasted monthly energies and since the 2017 Tier 1 energy was at a 99.9% load factor, the monthly energy difference from 2017 actuals to the 2019 forecast was added to Tier 2/3. He stated that because the additional 63,271,988 Tier 2/3 energy will no longer be sourced from NIPSCO generation, a reduction to the Forward Test Year electric operating revenues was made for an additional $1,629,317 of fuel expense reduction (Adjustments REV 1-R and FP 1-R). He stated the total adjustment reflected in REV 1A-R-19SS and FP 1A-R-19SS of $85,260,118 reflects all changes in industrial fuel based on the proposed new service structure. He noted that if this adjustment is not included, Forward Test Year electric operating revenues would be overstated and that if NIPSCO's service structure is not approved, this balance will need to be updated.

Mr. Westerhausen described two revisions to Rate 831. The first revision allows customers who are not ready to take service under Rate 831 on its effective date to take service under Rate 832 or Rate 833 through May 31, 2020. The second revision is related to the MISO Curtailment and Firm Capacity Options to provide at least two hours advance notice of MISO curtailments.

Mr. Westerhausen testified there is one revision to Rider 876 to clarify that service under Rider 876 cannot be used to nullify some or all of a MISO LMR obligation to curtail. Mr. Westerhausen supported Adjustment REV 1J-R-19R to increase Forward Test Year electric operating revenues in the amount of $2,187,672 to reflect the reallocation of commercial and small industrial customer revenues resulting from reallocation of the demand forecast utilizing 2018 actual billing determinants.

In response to Mr. Chriss' concerns with the Rate 726 class load profile data and 2019 billing determinants, Mr. Westerhausen testified that although the forecasted Billing Determinants in Total for Commercial and Small Industrial Customer Classes vary by less than 2%, there are material differences in the allocation between Rates 721, 723, 724, and 726. He stated that this misallocation was partially driven by a significant amount of customer migrations to Rate 726 between 2016 and 2018. Therefore, an adjustment was necessary to reallocate those billing determinants between those four rates based on 2018 allocation factors. He stated that the same methodology used by Financial Planning to allocate forecasted energy billing determinants by customer class to individual rates and blocks was utilized. He explained that billing determinants are planned for customer count, Demand (kW), and Energy (kWh) by rate. He described that this is completed within six rate classes – Residential, Commercial, Small Industrial, Large Industrial, Lighting, and Other. Forecasted customer count and kWh are provided by customer class by Demand Forecasting. He stated the Demand Forecast customer count and kWh are then passed to Financial Planning, where they are allocated to the individual rates and blocks, except for the Large Industrial Forecast, which is provided separately by customer. The allocation methodology uses billing data from a historical test period and their relationships to allocate the forecasted kWh and customer count to the rates and blocks. For the 2018 and 2019 budgets, the 12 months ended December 2016 was used as the historical test period, which was the last year end prior to the planning process. Mr. Westerhausen explained that demand is forecasted based on the percent change in kWh forecast as compared to the kWh in the test period. He noted that same percentage is applied to the kW in the test period to get forecasted kW for the budget. He explained that Adjustment REV 1J-R-19R kept the forecasted billing determinants for Rates 721, 723, 724, and 726 the same in total, but reallocated them between the four rates based on the 12 months ended December 31, 2018 actuals. He noted that the same allocation methodology was used to reallocate the forecasted kW between these four rates rather than using the growth factor performed by Financial Planning. He stated that the reason for this deviation from the planning process is that they already had established a reasonable amount of kW in total, and reallocating the forecasted kW resulted in reasonable results compared to 2018 actuals. He noted that these allocations were performed for the Commercial Class and Small Industrial Class, but did not change the Large Industrial or Other Customer Classes.

Mr. Westerhausen described Adjustment Rev 1E-R-19R and FP 1E-R-19R. He stated that NIPSCO proposed an adjustment for small migrations in its case-in-chief to annualize small customer migration that occurred in 2017 and the first half of 2018, which was necessary in the case-in-chief because the billing determinants for test year 2019 were based on the AFP, which used calendar year 2016 to allocate forecasted billing determinants by customer class to rates. He stated that an adjustment was made to the 2019 AFP to reallocate forecasted billing determinants based on 2018 actuals (see Adjustment Rev 1J-R-19R for further detail). He stated that since 2018 actual allocation of billing determinants was used to restate individual rate billing determinants, that process accounted for any 2017 and 2018 customer migrations that had occurred through December 31, 2018. As such, the small customer migration adjustment is no longer applicable and is being removed from rebuttal adjustments for billing determinants, revenues, and fuel.

Mr. Westerhausen testified the average system fuel was calculated by using the total fuel and purchase power of $321,765,239 divided by total fuel kWh of 12,034,825,315, resulting in an average fuel cost of .02674/kWh.

Mr. Westerhausen sponsored Attachment 19-R-L, an update to Attachment 19-C (Revised), which shows 2017, 2018, and 2019 billing determinants. He stated that Attachment 19-R-L was also updated for the additional migration of a large industrial customer currently served under Rate 833 to Rate 831, Plan Allocation in Adjustment REV 1J-R-19R, and reversal of Small Migration in Adjustment REV 1E-R-19R, and also included a correction to Rate 721 2019 kWh billing determinants. He noted that the 2,123,333 kWh for the 2019 Weather Normalization adjustment shown in Column K was not included in the 2019 Projected Billing Determinants Column M and that this correction results in the 2019 revised billing determinants decreasing by 2,123,333 kWh. He indicated that Attachment 19-R-L also included six insignificant corrections to 2017, 2018, and the starting kWh in Column I of 2019 Budget Billing Determinants that did not affect the 2019 billing determinants.

Mr. Westerhausen sponsored Attachment 19-R-M, NIPSCO's proposed standard contract for service. He stated the agreement has been revised from the proposed standard contract for the removal of Rate 830 and Rate 831 and added references to Rates 832 and 833. He also sponsored Attachment 19-R-O, NIPSCO's proposed standard contract for service for Rate 831 incorporating Tier 1, 2, and 3 contract demands and aggregation information specifically for this rate.

20. Overview of the Revenue Settlement. The Revenue Settlement entered into by and among NIPSCO, Industrial Group, NLMK, US Steel, CAC, Walmart, NICTD, Sierra Club, IMUG, and the OUCC resolves revenue requirements issues and other miscellaneous issues. The key terms of the Revenue Settlement are summarized as follows:

- NIPSCO's base rates will be designed to produce $1,482,166,740 prior to application of surviving Riders, which represents a decrease of approximately $63.648 million from the amount originally requested by NIPSCO. The revenue requirement reflects the depreciation study and accrual rates and amortization and a $2,000,000 decrease to NIPSCO's proposed O&M Expense. The agreed revenue requirement does not include:
    - All MISO related costs not included in FAC charges which had been recovered through base rates. Those costs shall be recovered instead through the RTO tracker; and
    - Costs related to the URT are removed from base rates. The URT shall be calculated and recovered as a separate line item on customer bills.
- NIPSCO's authorized NOI will be $271,211,585.
- The Revenue Settling Parties agreed that the WACC times NIPSCO's original cost rate base yields a fair return for purposes of this case, and agree that NIPSCO should be authorized a fair return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets as proposed in NIPSCO's case-in-chief (unless corrected in this proceeding); (2) NIPSCO's proposed capital structure as set forth below; and (3) NIPSCO's authorized ROE of 9.90%.

- NIPSCO's overall WACC is computed as follows:

	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%
Post-Retirement Liability	$66,142,914	0.00%	0.00%
Prepaid Pension Asset	$(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 depreciation accrual rates recommended by NIPSCO witness Spanos and presented in the Depreciation Study should be approved except that: (1) the amortization period for retired coal-fired generating units described in NIPSCO's case-in-chief shall conclude in 2032, which presumes the retirement of Schahfer in 2023 and the Michigan City in 2028; and (2) annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency expense included in demolition costs, as proposed by Industrial Group witness Gorman.

- NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding except that the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC Seven-Year Plan, FMCA, MATS, EDR, and Electric Rate Case Expense of seven years. If not already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

- NIPSCO agrees to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base at the time a final order is issued in this proceeding and the actual investment amount adjusted for depreciation as outlined in OUCC witness Blakely's direct testimony. NIPSCO agrees to implement the credit upon the retirement of the generating units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. The credit will be limited to the net plant investment value of the Schahfer and Michigan City generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in paragraph B.1(a); and (2) the NOI established in paragraph B.1(b) for purposes of its earnings test. NIPSCO agrees to hold annual pre-filing meetings preceding the 30-day compliance filing with interested stakeholders.

- The Revenue Settling Parties agree that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in

NIPSCO's revenue requirement at the ARAM, estimated at the time of this Agreement to be 26 years.

- The Revenue Settling Parties agree that NIPSCO's Unprotected and Other Excess ADIT balance, totaled approximately $137,789,071 as of December 31, 2017. NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. If not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization.

- Step 2 Rates shall be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agrees it shall not be permitted to include in rate base for Step 2 Rates plant in excess of the amount or value of plant projected in this Cause. The Revenue Settling Parties agree that Step 2 Rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Step 2 Rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019, and calculate the Step 2 Rates using those certified figures. NIPSCO will provide all Revenue Settling Parties with its certification. The Revenue Settling Parties and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Revenue Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 Rates were put into place.

- The Revenue Settling Parties agreed to the following issues related to rate design:

    - Rates should be designed with the Residential Customer Charge set at $13.50/month;

    - as proposed in Industrial Group witness Phillips' direct testimony and NIPSCO witness Westerhausen's rebuttal testimony, Rate 830 shall be split into Rates 832 and 833 which shall reflect the current structure of Rates 732 and 733, and provide for back-up and maintenance provisions reflected in current Rider 776; and

    - Rate 844 shall see no increase in its base rates resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago.

- The Revenue Settling Parties agreed to the following tracker and rider issues:

- NIPSCO agrees to flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero.
- NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years.
- NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief.

- NIPSCO commits to seek approval of a voluntary low-income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process NIPSCO has already established with interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

- The lamp charge for TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. The resulting revenue deficiency (estimated at NIPSCO's proposed COSS to equal approximately $52,500) will be allocated to other customer and NIPSCO-owned lamp types in Rate 850.

21. Revenue Settlement Supporting Testimony.[35]

A. NIPSCO Witness Sistovaris. Ms. Sistovaris and the other Revenue Settling Parties sponsored Joint Exhibit 1, which is a copy of the Revenue Settlement in this Cause, including the Formal Notice of Indiana Municipal Utility Group Joinder in Amended Partial Settlement Agreement filed May 15, 2019. She testified the specific objectives addressed in the Revenue Settlement include: (1) resolution of the revenue requirements issues; (2) resolution of issues related to the Residential Customer Charge; (3) resolution of issues relating to proposed Rate 830; (4) resolution of issues related to the impact on proposed Rate 844 customers; (5) resolution of issues relating to proposed Rate 850; (6) resolution of issues related to NIPSCO's proposals relating to proposed Riders 871, 872, and 877; and (7) resolution of issues relating to creation of a low-income program.

Ms. Sistovaris summarized the differences in the proposed revenue requirements among the parties. She testified that NIPSCO filed this case to: (1) reflect the evolution of the market for electricity for NIPSCO as well as for its largest customers in NIPSCO's service structure; (2) reflect in base rates the recent capital investments into NIPSCO's electric system, including infrastructure modernization and environmental controls; (3) revise its depreciation rates; and (4) align its rates and charges required to maintain safe and reliable service. She stated the majority of

[35] Sierra Club filed a notice of support for the Revenue Settlement stating that the direct and cross-answering testimonies of Ms. Allison to support the overall reasonableness of the fixed charge for residential service and the acceleration of depreciation for NIPSCO's coal-burning units.

the differences in the proposed revenue requirements among the parties can be reduced to three issues: (1) NIPSCO's authorized ROE; (2) NIPSCO's need to address unresolved impacts related to the TCJA, particularly the return of excess ADIT; and (3) NIPSCO's efforts to mitigate the effects of the requested change in depreciation rates. Additionally, there were other proposed differences to the revenue requirement related to proposed amortization periods for various regulatory assets and differences in pro forma operating costs.

In support of the agreed-upon ROE and the resulting authorized NOI, Ms. Sistovaris stated there was a balancing of interests among NIPSCO's stakeholders. She noted that too low of a return would provide a level of financial insecurity that would place inappropriate risk upon NIPSCO's ability to attract capital to provide reasonably adequate service and facilities. However, NIPSCO recognizes that returns have trended downward since its last rate case order. She stated that balancing the interest of all stakeholders, the Revenue Settling Parties agreed upon an ROE of 9.90%, which is lower than NIPSCO's requested ROE but higher than the ROE proposed by the OUCC, the Industrial Group, and Walmart.

In support of the agreed-upon treatment of the return of excess ADIT, Ms. Sistovaris stated the Revenue Settling Parties agreed that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460), shall be passed back in NIPSCO's revenue requirement at the ARAM, estimated at the time of the Revenue Settlement to be 26 years. She stated that the Revenue Settling Parties also agreed that NIPSCO's Unprotected and Other Excess ADIT balance (totaled approximately $137,789,071 as of December 31, 2017) shall be amortized $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. The Revenue Settling Parties agreed that at the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. Finally, NIPSCO agreed that if not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO will make a tariff filing that will reflect the ending of the amortization.

In support of the agreed-upon resolution of NIPSCO's request to modify its depreciation rates and cost recovery in rates, Ms. Sistovaris stated that the Revenue Settling Parties agreed to the depreciation accrual rates recommended by Mr. Spanos and presented in the Depreciation Study with two exceptions. First, those proposed depreciation rates are expected to result in a regulatory asset to be included in rate base and amortized over a period of years as described in NIPSCO witness Shikany's direct testimony. The Revenue Settlement provides that the amortization period of that regulatory asset shall conclude in 2032. Second, annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency expense included in demolition costs, as proposed by Industrial Group witness Gorman.

Ms. Sistovaris testified the Revenue Settling Parties agreed that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding, except that the amount of annual amortization expense shall be modified to reflect an amortization period for the TDSIC Remand, TDSIC Seven-Year Plan, FMCA, MATS, EDR, and Electric Rate Case Expense of seven years. She stated that NIPSCO agreed that if not already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO will make a tariff filing that will reflect the reduction in amortization expense.

Ms. Sistovaris stated the Revenue Settling Parties agreed that NIPSCO would implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base and rates resulting from the final order in this proceeding and the actual investment amount adjusted for depreciation as outlined in Mr. Blakely's direct testimony and also agreed to implement the credit upon the retirement of the generating units. She described the credit will be limited to the net plant investment value of the Schahfer and Michigan City generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. She explained that NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in the Revenue Settlement (paragraph B.1(a)); and (2) the NOI established in the Revenue Settlement (paragraph B.1(b)) for purposes of its earnings test. NIPSCO also agreed to hold annual pre-filing meetings preceding the 30-day compliance filing with interested stakeholders.

Ms. Sistovaris testified NIPSCO agrees that a NOI of $271,211,585 is an acceptable return on the fair value of its assets. With regard to the proposed changes to Rate 811, Ms. Sistovaris testified the Revenue Settling Parties agreed that the customer charge for Rate 811 will be $13.50 per month. She explained that for purposes of this proceeding, NIPSCO is willing to reduce its customer charge based on the result of a compromise between NIPSCO, CAC, and the OUCC.

With regard to the proposed changes to Rate 830, Ms. Sistovaris testified the Revenue Settling Parties agreed that as proposed in Mr. Phillips' direct testimony and Mr. Westerhausen's rebuttal testimony, Rate 830 will be split into Rates 832 and 833 which will reflect the current structure of Rates 732 and 733, and provide for back-up and maintenance provisions reflected in current Rider 776.

With regard to the proposed changes to Rate 844, Ms. Sistovaris testified the Revenue Settling Parties agreed that Rate 844 will see no increase in its base rates resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. She explained that NICTD, a regional commuter rail authority uniquely situated among NIPSCO's customers, is NIPSCO's only customer taking service under proposed Rate 844. She stated that NIPSCO believes that any unnecessary financial burden on NICTD will have a direct impact on economic development in the region. She noted that NICTD provides a vital transportation function within northwest Indiana directly adjacent to Chicago allowing for thousands of commuters from this region to travel to and from work in Chicago, funneling hundreds of millions of dollars of earned wages into the area each year.

Regarding proposed changes to Rate 850, Ms. Sistovaris testified the Revenue Settling Parties agreed that the lamp charge for TDSIC Light-Emitting Diode ("LED") NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. She explained the resulting revenue deficiency will be allocated to other customer and NIPSCO-owned lamp types in Rate 850 and that NIPSCO recognizes the important public service benefits that municipal street lighting provides and the individual efforts of IMUG in initiating and supporting the LED modernization of NIPSCO street lights. She testified the Rate 850 outcome is reasonable.

Ms. Sistovaris addressed proposed changes to NIPSCO's Tariff resulting from the Revenue Settlement by stating the Revenue Settling Parties agreed that: (1) NIPSCO will flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; (2) NIPSCO

shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years; and (3) NIPSCO's proposal for treatment of economic development rider contracts in Rider 877 shall be approved, including the deferral mechanism described in NIPSCO's case-in-chief.

Ms. Sistovaris testified the Revenue Settling Parties agreed that NIPSCO will seek approval of a voluntary low-income program within six months of a final order in this proceeding. She explained that other program details will be established in good faith through the collaborative process NIPSCO has already established with NIPSCO and interested stakeholders. She stated NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. She said funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

Ms. Sistovaris explained that NIPSCO initiated this proceeding to address three main drivers: (1) to change depreciation rates; (2) NIPSCO needed to address the impact of the TCJA, and; (3) NIPSCO is proposing a change in its large industrial service structure to address the changing economic landscape. She commended the efforts of all Revenue Settling Parties that led to the Revenue Settlement in the abbreviated time permitted by General Administrative Order 2013-5 and Ind. Code § 8-1-2-42.7 and stated the Revenue Settlement was only possible because of the collaborative and open efforts of all Revenue Settling Parties. She stated the Revenue Settlement represents a diligent effort by all Revenue Settling Parties to reach a comprehensive result. She explained that the complexity of the issues and the diversity of the Revenue Settling Parties dictated the need for compromise on the part of everyone involved, and the Revenue Settlement reflects a delicate balance that accommodates the interests of all Revenue Settling Parties in a reasonable way.

Ms. Sistovaris testified approval of the Revenue Settlement as it is written is consistent with the public interest. She stated that as the evidence reflects, the Revenue Settlement resolves complex, divisive, and controversial issues surrounding revenue requirement and a few other issues. Moreover, the Revenue Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost.

B. NIPSCO Witness Shikany. Ms. Shikany supported the Revenue Settling Parties agreement that NIPSCO should be authorized to implement its basic rates and charges for electric utility service in two steps: (1) the first change in rates will be based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in service, actual capital structure, and associated depreciation and amortization expense as of June 30, 2019 ("Step 1"); and (2) the second change in rates will be based on the agreed revenue requirement as of December 31, 2019, as adjusted, if necessary, to reflect the lesser of (a) NIPSCO's forecasted test-year-end rate base as updated in its rebuttal evidence ($4,115,502,071), or (b) NIPSCO's certified test-year-end net plant in service as of December 31, 2019 ("Step 2") and includes the amortization of $12,170,384 per year in the revenue requirement related to the pass back of the unprotected property and other unprotected excess ADIT to customers.

She stated that the Step 1 revenue requirement reflects NIPSCO's projected net utility plant in service, projected capital structure and the associated depreciation and amortization expense as of June 30, 2019, and maintains the amortization of the protected property excess ADIT using ARAM and unprotected property and other unprotected excess ADIT using ARAM and ten years, respectively. She explained that the Revenue Settlement provides for amortization to increase at Step 2 to reflect the pass back of $12,170,384 per year, and that Step 1 rates will go into effect on the next billing cycle following NIPSCO's submission of its Step 1 compliance filing.

She stated that the Step 2 revenue requirement reflects NIPSCO's projected net utility plant in service, projected capital structure and the associated depreciation and amortization expense as of December 31, 2019 and contains the additional pass back of the unprotected property and other unprotected excess ADIT and that Step 2 rates will be certified and go into effect, subject to refund, on March 1, 2020.

Ms. Shikany described the settlement adjustments agreed to by the Revenue Settling Parties. She testified that NIPSCO also updated the Costs of Customer Deposits and the Post-1970 ITC to correct clerical errors made during settlement negotiations, both of which had no impact on the overall WACC agreed to by the Revenue Settling Parties.

In summarizing the Step 2 revenue requirement, Ms. Shikany testified that NIPSCO proposes to recover the gross revenue amount of $1,482,166,740, which reflects a revenue increase of $46,608,036 as compared to test year pro forma results based on new service structure or a revenue decrease of $45,035,606 compared to test year pro forma results based on current rates, providing NIPSCO the opportunity to earn NOI of $271,211,585. She stated the agreed revenue requirement of $1,482,166,740 reflects a reduction of $63,648,449 from NIPSCO's case-in-chief proposal of $1,545,815,189 and a reduction of $62,891,513 from NIPSCO's rebuttal proposal of $1,545,058,253.

In summarizing the Step 1 revenue requirement, Ms. Shikany testified the Step 1 revenue requirement maintains the amortization of the unprotected property and other unprotected excess ADIT using ARAM and ten years, respectively and is based on the 12-month period ending June 30, 2019. Step 1 proposes to recover the gross revenue amount of $1,456,884,344, which reflects a revenue increase of $21,325,640 as compared to test year pro forma results based on new service structure or a revenue decrease of $70,318,002 compared to test year pro forma results based on current rates, providing NIPSCO the opportunity to earn NOI of $259,146,998.

Ms. Shikany explained the Revenue Settlement adjustments for Step 1. She testified that Settlement Adjustments OM 24-S2-S-19R, AMTZ 10-S2-S-19R, and AMTZ 11-S2-S-19R discussed above for Step 2 are applicable to Step 1. She testified the Step 1 revenue requirement is based on NIPSCO's current projections of utility plant in service, accumulated depreciation, and capital structure at June 30, 2019; therefore, the depreciation and some amortization expense adjustments, and the federal and state income taxes adjustment have been updated to include the pass back of the unprotected property and other unprotected excess ADIT at ARAM and ten years, respectively (the pass back of unprotected property and other unprotected excess ADIT at $12,170,384 per year, which will occur as of Step 2).

Ms. Shikany described the changes to NIPSCO's Tariffs as a result of the Revenue Settlement. She testified the Revenue Settling Parties agreed that: (1) NIPSCO will flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; and (2) NIPSCO shall discontinue its ECR Mechanism and shall recover the remaining regulatory asset over two years.

Ms. Shikany described the prospective annual credit mechanism agreed to in the Revenue Settlement. She stated the Revenue Settling Parties agreed that NIPSCO will implement an annual credit mechanism to reflect the difference between the net book value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base and rates resulting from the final order in this proceeding and the net book value at the date of the retirement as outlined in OUCC witness Blakely's direct testimony. She stated NIPSCO agreed to implement the credit upon the retirement of the generating units. She explained that the credit will be limited to the net book value of the Schahfer and Michigan City generating units embedded in base rates established in this Cause. She noted that NIPSCO will utilize a standardized form and will adjust: (1) the revenue requirement established in this proceeding; and (2) the NOI established in this revenue requirement for the purposes of its earnings test, and that NIPSCO agreed to hold annual pre-filing meetings preceding the 30-day filing with interested stakeholders.

Ms. Shikany testified that NIPSCO is seeking approval of depreciation accrual rates on an account by account basis. She stated that the depreciation study sponsored by Mr. Spanos in NIPSCO's case-in-chief, proposed specific depreciation rates by FERC account. She stated that the Revenue Settling Parties agreed that the depreciation accrual rates would be modified as described above to remove $26 million in contingency expense included in demolition costs and reflect the 2032 conclusion of the amortization period for the regulatory assets. Ms. Shikany stated that NIPSCO is requesting approval of these modified depreciation rates by FERC account.

Ms. Shikany explained that: (1) NIPSCO is seeking accounting authority to continue to defer, as a regulatory asset; discounts offered to certain customers under its Economic Development Rider for recovery in a future rate case in a manner consistent with the 44688 Rate Case Order; (2) NIPSCO is seeking authority to defer, as a regulatory liability, an amount equal to 100% of annual OSS margins net of expenses and back-up and maintenance demand margins, both for pass back through the RTO Tracker; and (3) NIPSCO is seeking authority to defer the remaining net book value of coal generation assets as a regulatory asset within rate base after the assets are retired. She testified that NIPSCO is requesting Commission approval of the deferrals.

C. NIPSCO Witness Westerhausen. Mr. Westerhausen explained how the Revenue Settlement rate-specific revenue requirement is calculated for proposed Rate 844 – Railroad Power Service, and he sponsored the proposed mitigation updated for the settlement revenue requirement and the adjustment for Rate 844. He also described and supported the Revenue Settling Parties' agreement that TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase.

Mr. Westerhausen testified that the Revenue Settling Parties agreed that Rate 844 shall see no increase in its base rates given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. He explained that keeping the demand rate at $16.85 and the two block energy rates at $0.041718 and $0.039468, resulted in the Rate 844

proposed mitigated revenue requirement excluding other revenue being $2,119,429 and that adding $26,855 in other revenue credits results in the proposed mitigated revenue for Rate 844 being $2,146,284. He explained that although the current Rate 744 two block energy rates are $0.041731 and $0.039481, these rates have been updated to reflect the forecasted rates to go into effect with the first billing cycle of October 2019 to adjust for the amortization roll off of the three-year amortization of electric vehicle expenses that was approved in the 44688 Rate Case Order.

Mr. Westerhausen testified that the Revenue Settling Parties agreed that TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. He stated this agreement is responsive to IMUG's testimony that the proposed Rate 850 rate increases to those municipalities that were the most prepared and first had their NIPSCO-owned street lights converted to LED would receive a disproportionate rate increase. He explained that NIPSCO recognizes and appreciates IMUG's concerns, and this agreement is responsive to those concerns. He testified that the Rate 850 settlement provision was very important to IMUG and necessary for their participation in the Revenue Settlement and that this adjustment only affects other customers within Rate 850. In Joint Exhibit 8, which was admitted in lieu of cross examination of Mr. Westerhausen, NIPSCO stated that the calculation of the cost of the Rate 850 agreement had been calculated on a monthly basis, but reported as an annual number. This resulted in an annual shortfall of revenue of $632,110. NIPSCO agreed with the OUCC to allocate only one-half of the revenue shortfall to NIPSCO's other Rate 850 customers and that NIPSCO would not seek recovery of the remainder from its other customers.

Mr. Westerhausen sponsored NIPSCO's proposed mitigation based on the Revenue Settlement's revenue requirement and the adjusted Rate 844 revenue requirement. He testified the total revenues proposed are based on an ACOSS that utilized a 4CP production allocation. He explained that with Rate 831 held at parity, the revised rate increase for all the rate classes except Rates 831 and 844 is 6.66%. Mr. Westerhausen also updated Attachment 19-R-F to his rebuttal testimony for the Revenue Settlement's revenue requirement and for the adjustment of Rate 844 in order to establish the allocation factors for NIPSCO's surviving tracking mechanisms.

D. OUCC Witness Blakley. Mr. Blakley's Revenue Settlement testimony addressed two items. He detailed the Revenue Settling Parties' agreement regarding the revenue credit mechanism related to the Schahfer and Michigan City Generating Stations. The revenue credit mechanism recognizes the net rate base value of the stations at the time the rates are approved in this Cause, then reduces the plant investment for annual depreciation at the time the first annual revenue credit mechanism is implemented. The mechanism will then recalculate NIPSCO's return on the reduced plant investment of Schahfer and Michigan City. He explained the difference between the return embedded in NIPSCO's base rates for Schahfer and Michigan City and the annual recalculated return based on the reduced plant value will be credited back to customers annually through a revenue credit mechanism filing.

Mr. Blakley also described the Revenue Settling Parties' agreement on excess ADIT to be returned to ratepayers. He described how the agreement will pass back approximately $203,164,460 of protected excess ADIT using ARAM over an estimated period of 26 years. Mr. Blakley also explained how the refund of unprotected and other excess ADIT of approximately $137,789,071 will start at $12,170,384 annually to begin after Phase 2 rate implementation on or

around March 1, 2020. At the time of NIPSCO's next rate case, the total amount of unprotected excess ADIT to be passed back will be determined and the agreed amortization may be adjusted.

Mr. Blakley testified these two portions of the Revenue Settlement generate customer benefits that were achieved only in settlement, as there was not consensus on either item in the parties' prefiled testimonies. He concluded that in context with the other terms, the entire Revenue Settlement serves the public interest and should be approved, in its entirety, without modification.

E. OUCC Witness Eckert. Mr. Eckert testified that if approved, the Revenue Settlement will provide certainty regarding critical issues, including revenue requirements, authorized return, and other miscellaneous issues. He testified that the Revenue Settlement was a result of intense negotiations with each party offering compromise to challenging issues, including assessing the litigation risk that the tribunal will find the other side's case more compelling. He stated that while the Revenue Settlement represents a balance of all interests, given the number of benefits provided to ratepayers, the OUCC believes the Revenue Settlement is a fair resolution, supported by evidence, and should be approved.

Mr. Eckert testified that as a result of the Revenue Settlement, NIPSCO's base rates reflect a lower revenue requirement than NIPSCO's initial proposal with the system-wide revenue increase of approximately 3.25%, thereby reducing the revenue increase impact for all NIPSCO's customers relative to NIPSCO's original proposal. He testified the Revenue Settlement resolves the TCJA issues and accounts for the changes to NIPSCO's revenue requirement necessary to address the TCJA and the Commission's order in Cause No. 45032-S5.

Mr. Eckert testified the ratepayer benefits in the Revenue Settlement include: (1) a $13.50 monthly residential customer charge – a $0.50 decrease from the current $14 charge and $3.50 less than NIPSCO's initial request of $17.00; (2) a 9.90% authorized ROE compared to NIPSCO's proposed increase to 10.80%; (3) resolving all issues regarding the TCJA; (4) NIPSCO's commitment to seek approval of a voluntary low-income program and establish a collaborative process to work out the program details (the cost of which is not reflected in the agreed revenue deficiency in this case); (5) certain exceptions to the depreciation accrual rates recommended by NIPSCO, resulting in a reduction to the revenue requirement; (6) adjustments to NIPSCO's proposed annual amortization expense; (7) an annual revenue credit mechanism reflecting the difference between the value of Schahfer and Michigan City units in NIPSCO's rate base at the time a final order is issued and the actual investment amount adjusted for depreciation; (8) changes to Rates and Tariffs; and (9) additional benefits negotiated by the Revenue Settlement.

Mr. Eckert explained that NIPSCO proposed a 10.80% ROE and the OUCC, Industrial Group, and other intervenors advocated for a considerably lower ROE applied to NIPSCO's original cost rate base. He testified that as a result of the negotiations, a compromise was reached, resulting in a 9.90% ROE and elimination of the fair value increment. Mr. Eckert testified a lower ROE benefits ratepayers by reducing the return on the rate base ultimately reducing the revenue requirement by approximately $23.8 million. He stated the Revenue Settlement establishes a balanced plan that is in the interest of both ratepayers and shareholders.

Mr. Eckert testified that the impacts of the TCJA lowered NIPSCO's annual revenue requirement by approximately $20.0 million as addressed in the Revenue Settlement. Mr. Eckert

also testified that the Revenue Settlement reduced test year O&M expense by $2 million, a reduction to amortization expense in the amount of $7,789,765, and a reduction in depreciation expense of $29 million.

With regard to treatment for OSS margins in the RTO Tracker, Mr. Eckert testified that flowing through 100% of OSS margins is an offset to ratepayers who are paying NIPSCO's retail rates to support the O&M expenses and provide a return of and a return on the assets that support OSS. He stated that ratepayers pay rates that reflect the MISO administrative fees, which provide for MISO to administer OSS of NIPSCO's excess generation. Additionally, 100% tracking of OSS margins will simplify the calculation of the OSS margin component of NIPSCO's proposed RTO Tracker and will provide transparency in the flow through of OSS margins. He testified that the Settling Parties agreement to continue NIPSCO's EDR proposal, including the deferral mechanism, will continue to bring economic benefits to NIPSCO, its ratepayers, and the region.

Mr. Eckert testified NIPSCO's commitment to seek approval of a voluntary low-income program within six months of an order in this proceeding. He stated that the program funding will be voluntary for all customers will not impact NIPSCO's revenue requirement.

Mr. Eckert concluded that the OUCC recommends that the Commission find the Revenue Settlement to be in the public interest and approve it in its entirety.

F. Industrial Group Witness Gorman. Mr. Gorman provided testimony in support of the Revenue Settlement and recommended that the Commission approve the settlement as reasonable and in the public interest.

Mr. Gorman testified that the Revenue Settlement reasonably resolved the parties' contested revenue issues. Specifically, he testified the Revenue Settlement reduced the proposed revenue increase by 57%, decreasing the proposed $111.4 million increase by $63.648 million. He testified that each of the revenue compromises, relative to the range of issues in the case, provide a reasonable outcome as they impact the total revenue requirement. He testified that the Revenue Settlement reflected a 9.90% ROE, which is in line with the ROE authorized by the Commission in NIPSCO's last base rate case. He added that the lack of change in capital market costs since that time supported finding a ROE reasonably comparable to the last case. Mr. Gorman also noted that NIPSCO had adjusted its proposed amortization of excess unprotected ADIT to ten years, and that the overall adjustment to operating expenses is appropriate and consistent with the compromise resolution of issues in the case.

22. Revenue Settlement Opposing Testimony.

A. ICC Witness Medine. Ms. Medine addressed three aspects of the Revenue Settlement: (1) approval years in advance of the accounting treatment and amortized recovery of undepreciated costs that NIPSCO will receive when it decides to retire any existing coal generation resource; and (2) any aspect of the settlement that locks-in specific retirement dates for any existing coal generation resource. In addition, she addressed why NIPSCO should only be allowed to include costs that are regularly adjusted outside base rates in the MISO bid prices for the coal units and should not be allowed to include costs that are recovered through base rates.

Mr. Medine recommended that the Commission deny approval of accounting treatment and amortized recovery that NIPSCO would receive if and when it retires any existing coal generation resources, and require NIPSCO to seek that relief at or near the time of actual retirement. She also recommended that the Commission avoid giving explicit or implicit approval to any specific date for retirement of any specific existing coal generation resource at this time. She recommended that the Commission limit NIPSCO from including variable operating costs in its offer price to MISO that are being recovered in base rates. Finally, she recommended that the Commission give guidance to NIPSCO for its 2021 IRP.

B. ICC/ICARE Witness Griffey. Mr. Griffey testified he does not oppose the Revenue Settling Parties' decision to set depreciation accrual rates for the coal units based on assumed lives ending in 2032. However, he recommended the Commission reject the aspect of the Revenue Settlement that would have it pre-approve now, years in advance of when NIPSCO may actually retire the units, regulatory asset treatment for sunk costs and pre-ordained amortization based on an assumption that the Schahfer units will all retire in 2023 and Michigan City in 2028.

Mr. Griffey noted a legislative Task Force will present findings in 2020 concerning the impacts of changing electric generation portfolios. He stated the Commission cannot know today what the statewide policies and regulatory statutes will be in 2023 and beyond thus making it premature to preordain in 2019 what accounting treatment and/or amortization treatment NIPSCO should receive if and when it actually retires existing generation resources in or after 2023.

Mr. Griffey stated that given the flaws in NIPSCO's IRP retirement and replacement analysis and the Task Force's mandate, he recommended the Commission: (1) decline to adopt any aspect of the settlement that forecloses flexibility; and (2) decline to approve explicitly or implicitly NIPSCO's professed retirement intentions based on its flawed IRP. He further recommended the Commission direct NIPSCO to: (1) perform an integrated retirement and replacement analysis in its 2021 IRP; and (2) seek regulatory and accounting treatment for any retiring coal plants at or near the time of actual retirement.

C. LaPorte Witness Cearley. Mr. Cearley took issue with the Revenue Settlement proposed cost of equity of 9.90% as being reasonable based on below average customer satisfaction results. He made two recommendations: (1) the Commission should adopt a return toward the bottom of the proposed range to reflect NIPSCO's lack of customer focus and poor customer satisfaction performance levels; and (2) NIPSCO's proposals to address its environmental and disproportionate level of large industrial load should have the effect of mitigating NIPSCO's risk. In response to the Commission's docket entry question, LaPorte stated that Mr. Cearley believes that a 25 to 50 basis point downward ROE adjustment for the elimination of each of these significant risk factors is appropriate and reasonable. LaPorte's docket entry response stated that this recommendation is further supported by Mr. Cearley's recognition in his direct testimony of the compounding effect of NIPSCO's repetitive risk adjustments to its return calculations based on environmental risks and its requests for upward risk adjustments due to a disproportionate level of large industrial load in its last three to four rate case proceedings.

23. Revenue Settlement Reply Testimony.

A. NIPSCO Witness Sistovaris. In response to LaPorte witness Cearley's criticism of NIPSCO's J.D. Power results and recommendation that the ROE in the Revenue Settlement be rejected, Ms. Sistovaris first noted that the J.D. Power surveys attached to his testimony do not support his claims. She explained that those surveys show on both the residential- and business- customer satisfaction side, NIPSCO's scores have been improving and that NIPSCO has been improving relative to its peers. Notably, NIPSCO is moving closer to the average survey result. She stated that on the residential side, NIPSCO has grown from a score of 645 in 2016 to a score of 706 in 2018 and that over that period, its distance from the average score has been cut in half. On the business side, NIPSCO's score has grown from 671 to 760, and it is almost at the average score. Additionally, J.D. Power has listed NIPSCO among the nation's most improved electric utilities in 2010, 2012, and 2015. She testified that these results show improvement, including improvement compared to NIPSCO's peers.

B. NIPSCO Witness Shikany. Ms. Shikany testified that Ms. Medine and Mr. Griffey seem to misunderstand the relief requested in this case. She explained this case is not about NIPSCO's preferred portfolio in its 2018 IRP, generation transition, or selecting a portfolio of resources. In fact, the preferred portfolio in the 2018 IRP is irrelevant to the issues in this case. She stated that this case is not about locking in retirement dates for NIPSCO's coal-fired generation. Rather, this is a general rate case, and as part of that general rate case, NIPSCO has sought approval of new depreciation accrual rates and has submitted a depreciation study. Ms. Shikany said that neither Ms. Medine nor Mr. Griffey took issue with the depreciation study or the depreciation rates that come out of the depreciation study. In fact, Ms. Medine specifically acknowledged that she takes no issue with the depreciation rate for NIPSCO's steam production plant, which underlies the Revenue Settlement. She stated that because the ICC and ICARE do not represent customers in this proceeding, the Revenue Settlement has no effect on them, and the only issue that may concern them (depreciation lives for coal plants), they explicitly accept.

Ms. Shikany testified that much of ICC and ICARE testimony is posturing for some future case that has not been filed rather than having anything to do with the relief NIPSCO seeks in this Cause. She noted that the ICC has intervened in four NIPSCO cases: this one, two PPA cases (Cause Nos. 45195 and 45196), and one joint venture case (Cause No. 45194). She explained that in all four cases, they have opposed NIPSCO's relief, yet none of those cases has any impact on the ICC, a fact that Ms. Medine admits when she notes that the "wind projects [in Cause Nos. 45195 and 45196] contribute very little UCAP and therefore have less relevance to the IRP which is focused on resources." Ms. Shikany stated that if those cases are irrelevant and have "very little impact" on the ICC's core issue (the IRP), then it is troublesome that the ICC chose to intervene and take up valuable resources to oppose relief "having very little impact." Instead, the ICC could have simply stated its issues with the IRP (which it has already done in the IRP process) and taken no issue on the ultimate relief sought – relief which every other party (all of whom represented actual customers who pay NIPSCO utility rates) agreed should be granted. She testified that this case contributes zero UCAP and therefore has even "less relevance to the IRP," and therefore less effect on the ICC and ICARE.

Ms. Shikany noted that both Ms. Medine and Mr. Griffey testified that NIPSCO's regulatory asset treatment resulting from the Revenue Settlement is unnecessary at this time and

should be deferred until the coal plants are actually retired. She stated the Revenue Settling Parties would not have reached a settlement that delayed the return on and of its investment in coal-fired generation until 2032 without granting the proposed regulatory asset treatment.

Ms. Shikany testified that deferring a decision on the regulatory asset treatment until the coal plants are actually retired would not be wise and is inconsistent with proper ratemaking. She described that this case is about establishing electric rates and, as part of that determination, setting new depreciation accrual rates. She explained that in the normal course, depreciation accrual rates would be set to recover the remaining book value over the remaining estimated useful life of the assets. She stated that the only evidence that has been introduced concerning the proper estimated useful life of the Schahfer units is 2023 and of the Michigan City unit is 2028. She testified that the ICC and ICARE have not proposed a different estimated useful life of these generating stations for depreciation purposes than that proposed by NIPSCO. She explained that under this scenario, NIPSCO would recover the remaining investment of Schahfer over the next four years and Michigan City over the next nine years at which point NIPSCO would fully recover its remaining investment in these units and would recover a return on that remaining investment. Ms. Shikany testified that from the outset of this case, NIPSCO has recognized that such a result would produce significant rate increases and has, accordingly, proposed to delay the recovery of the remaining investment over a longer period on the condition that the resulting regulatory asset would be included in rate base. She noted that every group representing customer interests in this case has either agreed to that condition or has not opposed it. She indicated that absent this condition, NIPSCO would recover the entire investment by the physical retirement date, which would result in significantly higher customer rates that would not be agreed to by the Revenue Settling Parties in the Revenue Settlement. She stated that the only parties opposing that condition are coal interests that will have absolutely no interest in whether NIPSCO earns a return of and on its investment.

Ms. Shikany stated that the only evidence that has been introduced of the estimated useful lives of NIPSCO's coal plants is 2023 and 2028. She explained that if NIPSCO were to come out of this case without either: (1) depreciation rates which would match recovery to those useful lives; or (2) assurance that it will recover both a return of and on any costs that would not have been recovered at the time of retirement, NIPSCO faces a risk of immediate write-off under GAAP, which would have a negative impact on the financial statements and the investor community. She also explained that 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 NIPSCO's cost of capital. She stated that not facing the depreciation issue today when it should be addressed would result in needless harm to an Indiana utility and its customers. Ms. Shikany testified there is a very real need to either set appropriate depreciation rates based upon the estimated useful life today or, if that result needs to be mitigated, assure NIPSCO that it will recover a return of and on its investment.

Ms. Shikany testified the deferral mechanism to which the parties have agreed provides that NIPSCO will recover a return of and on the investment through 2032. She explained that so long as those coal plants are retired between now and 2032, there would be absolutely no difference to the relief that is set forth in the Revenue Settlement. She explained that if Schahfer were to remain in service until 2028, the remaining net book value at the time of the retirement would be smaller (due to five years of additional depreciation expense) and NIPSCO would simply amortize

that remainder over a period shortened by five years. She noted that under either scenario, NIPSCO is recovering a return of and on the same investment and, therefore, there is no harm to customers from granting the regulatory asset treatment today.

In response to Ms. Medine's and Mr. Griffey's testimony that the Commission should wait to grant the regulatory asset treatment until after the legislative Task Force completes its work, Ms. Shikany stated that the legislative Task Force is not going to have an effect on the relief NIPSCO seeks in this proceeding and certainly no effect that could not be revisited at that time. Ms. Shikany stated that any number of changes could be implemented after they are adopted and would have no effect on this case. She said that as it is, there are no retirements planned until three years after the Task Force meets affording plenty of time to reflect legislative changes should they occur. She testified that the issue in this case is how much customers today should pay in rates so that NIPSCO can be assured recovery of a return of and on its investment in coal-fired generation that has served its customers very well for many years.

In response to Mr. Griffey's recommendation that the Commission should decline any aspect of the Revenue Settlement that forecloses flexibility and decline to approve explicitly or implicitly NIPSCO's retirement dates, Ms. Shikany testified that no aspect of the Revenue Settlement does either. She noted that there continues to be great flexibility for NIPSCO to adapt to the changing environment. She reiterated that this case is purely about cost recovery today, and the Commission is not approving explicitly or implicitly retirement dates; rather, it is setting depreciation accrual rates. She stated that the actual lives of these generating facilities may be different than the lives that are estimated today, which is not uncommon. She testified that if estimated lives change, the differences will be addressed through prospective changes in depreciation accrual rates that would be proposed in a subsequent base rate proceeding.

C. NIPSCO Witness Augustine. Mr. Augustine responded to Mr. Griffey and Ms. Medine's claims that NIPSCO's 2018 IRP contained multiple flaws. Mr. Augustine sponsored his rebuttal testimonies in Cause No. 45194 (Attachment 6-S1-R-A), 45195 (Attachment 6-S1-R-B), 45196 (Attachment 6-S1-R-C), and NIPSCO's response to stakeholder comments on the 2018 IRP (Attachment 6-S1-R-D) and testified that within his rebuttal testimony in this Cause and in these other responses and testimonies, he addressed concerns related to industrial load uncertainty, end effects calculations, and the 20-year versus 30-year analysis time horizon, retirement, and replacement analysis modeling and associated portfolio development assumptions, future coal plant capital and maintenance costs, environmental regulation assumptions, scenario development and the IRP's stochastic risk analysis, the flexibility of NIPSCO's preferred portfolio, wind and solar cost and operational assumptions, congestion and transmission cost assumptions, and ancillary services cost assumptions. He noted that many of the concerns raised by witnesses Griffey and Medine related to NIPSCO's 2018 IRP in their responses to the Revenue Settlement were litigated in significant detail in Cause Nos. 45195 and 45196, wherein the Commission concluded that "[w]hile ICC criticized various aspects of NIPSCO's modeling, witness Augustine, in rebuttal, adequately addressed those criticisms."[36]

[36] Order in Cause No. 45195 (IURC 06/05/2019) (the "45195 Order"), p. 9, and Order in Cause No. 45196 (IURC 06/05/2019) (the "45196 Order"), p. 10.

Mr. Augustine responded further to Mr. Griffey's claims that NIPSCO's two-step retirement and replacement analysis is inherently flawed and, Ms. Medine's suggestion that the Commission should direct NIPSCO to perform integrated planning that does not separate retirement and replacement decisions. He testified that the IRP analysis approach allowed NIPSCO to first fully evaluate a wide range of retirement concepts and then to secondly evaluate replacement portfolios across a range of objectives and a range of commitment duration and diversity outcomes. He testified that in its 45195 and 45196 Orders, the Commission affirmed its understanding of this process, and in response to the ICC's claims that the approach was biased, stated that the "ICC fails to recognize that the two analyses have distinct purposes."[37] He noted that the first purpose of evaluating the range of retirement options is most relevant because the issue at hand is the economic useful life of the current coal fleet and the depreciation rates for NIPSCO's existing assets, and not a specific replacement decision. He explained that throughout its 2018 IRP, NIPSCO found that the early retirement of coal capacity is cost effective for customers whether the existing coal units are replaced with the least cost renewable options from the RFPs conducted as part of the 2018 IRP or with higher-cost MISO market energy purchases and capacity costs based on cost of new entry. He stated Mr. Griffey has not refuted this, and his efforts to compare retirement portfolios from this first step of the analysis with replacement portfolios that were constructed based on different objectives in the second step should not distract from the clear finding that retaining coal is higher cost than any number of alternatives. He stated again that NIPSCO incorporated other decision metrics in its analysis, including cost risk, reliability risk, environmental stewardship, and the impact on employees and the local economy in arriving at its preferred portfolio. He stated that if NIPSCO followed Mr. Griffey's guidance to select the lowest cost portfolio over the next 20 years, then a portfolio that retires all coal in 2023 would have been chosen. He testified that instead, a plan that staggers the retirements and replaces capacity with a mix of different renewables with different commitment durations was selected.

Mr. Augustine responded to Mr. Griffey and Ms. Medine's suggestion that industrial load uncertainty, particularly related to proposed Rate 831, was not sufficiently addressed in the 2018 IRP. He testified that: (1) NIPSCO's 2018 IRP evaluated a low load scenario with substantial industrial load leaving the system; (2) the competitiveness of the existing coal fleet and alternative replacement renewable resources is driven primarily by the cost structure of such resources and their position in the MISO market and not NIPSCO's internal load; and (3) future loss of firm load can be managed through the flexibility inherent in NIPSCO's preferred portfolio. He added that he is now aware that the partial settlement with five large industrial customers in this Cause is based on subscription of approximately 194 MW of firm load to Rate 831. He stated that when offset by the loss of industrial interruptible capacity that NIPSCO currently considers a supply resource, the impact of this rate design change on NIPSCO's load obligations is approximately 60 MW, a level that is far less than the load uncertainty ranges evaluated in the IRP and represents a small fraction of total demand.

Mr. Augustine responded to Mr. Griffey's testimony that the commitment of less than 200 MW for Tier 1 service is only for five years, which should support a decision to maintain flexibility about when to retire the coal plants, and Ms. Medine's suggestion that in the future NIPSCO should use a load forecast that accounts for any possible resulting change in load both in the initial five years of Rate 831 contracts and in later years. He agreed that load uncertainty should continue to

[37] 45195 Order, p. 9, 45196 Order, p. 10.

be evaluated and that the industrial load uncertainty in NIPSCO's service territory is one reason to ensure flexibility in the supply portfolio; however, he testified that NIPSCO's preferred portfolio accomplishes this far better than Mr. Griffey's preference to continue operating the coal plants. He demonstrated that continued operation of the coal fleet is immediately higher cost than the alternatives, while NIPSCO's replacement plan allows for flexible procurement of new resources with different commitment durations over time, all at a lower cost. He stated that Mr. Griffey falsely attempts to claim that lower industrial load in the Challenged Economy scenario was the reason why coal units looked more economic, when the real driver of this result was the lack of a carbon price in that scenario. He stated that all of the scenarios evaluated by NIPSCO in the 2018 IRP, including the one designed by the ICC, showed that early retirement of the coal plants results in lower customer costs.

Finally, Mr. Augustine testified that he does not believe that Mr. Griffey's attempts to compare NIPSCO's process and situation to Vectren's are valid. In response to his claims that like Vectren, "NIPSCO plans to put most of its eggs in [one] basket," Mr. Augustine asserted that this is not true at all. NIPSCO plans to phase out coal plants over a ten-year period, NIPSCO owns an approximately 500 MW existing natural gas combined cycle plant that is part of its long-term preferred portfolio, along with other smaller natural gas peaking units, and NIPSCO plans to procure a mix of owned and contracted wind, solar, and storage resources, allowing for significant diversity and flexibility in resource procurement as technology and markets evolve. He noted that the Commission recently acknowledged the distinction between Vectren's plan and NIPSCO's and affirmed that "NIPSCO's 2018 IRP was explicitly developed to maintain optionality to enable making adjustments and modifications as circumstances warrant."[38]

Mr. Augustine also testified that Mr. Griffey's claim that "NIPSCO's IRP ignored options that could allow the coal units to remain in service" is false, as NIPSCO explicitly developed a range of portfolios that keep coal plants on longer, including with less stringent environmental regulations. He explained that NIPSCO also evaluated a scenario developed by the ICC that assumed *no* additional environmental capital expenditures would be required for the coal fleet and still found that early retirements were lower cost. Additionally, NIPSCO evaluated coal-to-gas conversion options and found that renewable replacements were lower cost than conversion. He stated that Mr. Griffey's claims that NIPSCO "failed to consider the possibility of higher gas and energy prices without CO2 taxes" and failed to update assumptions related to load uncertainty and wind operational parameters are false. He testified that NIPSCO evaluated a scenario with higher gas and energy prices and no CO2 price, designed specifically by the ICC to test the possibility Mr. Griffey claims was ignored, and found that early coal retirement and replacement with renewables was lower cost. In addition, NIPSCO also addressed load uncertainty sufficiently and confirmed that the overall cost and performance of the specific wind resources currently being added to the portfolio are consistent with the IRP's assumptions for wind resources.

D. NIPSCO Witness Campbell. Mr. Campbell responded to Ms. Medine's request that NIPSCO exclude non-FAC costs for purposes of MISO offer prices for NIPSCO's coal units. He testified that this issue was raised and rejected by the Commission in its April 29, 2019 Order in Cause No. 38706 FAC 122. He stated that in that Order, the Commission found that

[38] Order in Cause No. 45195 (IURC 06/05/2019) (the "45195 Order"), p. 10, and Order in Cause No. 45196 (IURC 06/05/2019) (the "45196 Order"), p. 11.

NIPSCO demonstrated that its current offer strategy of its generation units into the MISO energy market was reasonable.[39] In addition, NIPSCO did not include inappropriate components of its offers to MISO, nor were they imprudent with respect to its generation decision-making. As such, the Commission should reach the same conclusion in this case. Mr. Campbell testified that Ms. Medine's view that including costs that are not tracked in NIPSCO's FAC would result in the possibility of over recovery of costs would actually result in an under recovery of costs related to the sale of energy into the MISO market. He explained that the variable costs of production that are built into the agreed revenue requirement are based upon production cost modeling, which is based upon NIPSCO's variable costs of production in relation to other sources of power offered into the MISO market. He stated that if NIPSCO were not to include all of the variable costs of production in its actual bids, all else being equal, NIPSCO's units would dispatch more energy than is assumed in the rate case. In other words, NIPSCO would incur variable costs of production that are not tracked and that would be in excess of the amount assumed in this case.

Mr. Campbell testified that even if the Commission allowed NIPSCO to recover its higher projected variable costs in base rates, NIPSCO's retail customers would be harmed. He explained that MISO maximizes the efficient use of the energy grid by utilizing its Security Constrained Economic Dispatch software that matches energy needs with resources based upon capability and price. He stated that were NIPSCO to offer its generation into the MISO market without consideration of its related variable costs, its offer price would not reflect the economic cost of running its generation units, its generating units would be uneconomically dispatched, and its retail customers would likely end up paying higher costs.

24. Overview of the Rate 831 Settlement. On May 17, 2019, NIPSCO, Industrial Group, NLMK Indiana, and US Steel filed the Rate 831 Settlement.[40] The Rate 831 Settling Parties stated that the Rate 831 Settlement fairly and reasonably resolves issues related to Rate 831, subject to Commission approval without any modification or condition that is unacceptable to the Rate 831 Settling Parties. The Rate 831 Settlement looks to resolve all issues related to implementation of Rate 831. The key terms of the Rate 831 Settlement are summarized as follows:

- The Rate 831 Settling Parties[41] agree that NIPSCO's COSS should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 MW.[42] The Rate 831 Settling Parties agree that $149.438 million (exclusive of approximately $2.827 million in "other revenues") shall be allocated to Rate 831.

- For purposes of tracker allocations, the Rate 831 Settling Parties agreed:

    - Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO witness Westerhausen's Verified Rebuttal Testimony

[39] The Commission stated (at 9) that "NIPSCO has adequately demonstrated that it 'has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]' Ind. Code § 8-1-2-42."

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

[41] US Steel filed testimony only related to Rate 831, and thus supports the settlement COSS as it relates to the rates, charges, and trackers related to Rate 831, and takes no position on the remaining rate design.

[42] As shown in Confidential Exhibit C to the Rate 831 Settlement, Tier 1 subscriptions will be less than the presumed MW level, but this shall not alter the stated revenues assigned to Rate 831.

(updated for the settlement revenue requirement and the adjustment for Rate 844), shall be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms;

- Rate 831 Implementation Agreement Exhibit B, which is Attachment 19-R-E to NIPSCO witness Westerhausen's Verified Rebuttal Testimony (with no changes), sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism; and
- For the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO witness Westerhausen's Verified Rebuttal Testimony (updated with the settlement revenue requirement), reflect the allocation factors for TDSIC purposes.

- For purposes of Rate 831 rate design, the Rate 831 Settling Parties agreed:
  - Except as otherwise provided in the Rate 831 Settlement, the Rate 831 Settling Parties agree that Rate 831 shall be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in Paragraph B.1. of the Rate 831 Settlement.
  - The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the COSS presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in Paragraph B.1. of the Rate 831 Settlement.
  - For purposes of the AAQFPTC, the Rate 831 Settling Parties agree that the provision shall be amended by adding the following language: "If the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period."
  - The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial five-year contract is set forth in Rate 831 Implementation Agreement Confidential Exhibit C. The Rate 831 Settling Parties agree that Tier 1 subscriptions reflected in Rate 831 Implementation Agreement Confidential Exhibit C shall be binding upon each customer in the event of the approval of this Agreement without modification.
  - The Rate 831 Settling Parties agree that a transition period, lasting from the date on which Step 1 Rates become effective until June 1, 2020, shall provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and capacity needs. The Rate 831 Settling Parties agree that

the terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

25. Rate 831 Settlement Supporting Testimony.

A. NIPSCO Witness Westerhausen. Mr. Westerhausen summarized the Rate 831 Settlement. He testified that the Rate 831 Settlement reflects the Rate 831 Settling Parties agreement on issues related to Rate 831 between and among themselves, including implementation. He stated the specific objectives addressed in the Rate 831 Settlement include resolution of: (1) the allocation of costs to Rate 831, eliminating the risk for a Phase 2 proceeding provided the Revenue Settlement, revenue allocation, and rate design of Rate 831 as proposed by NIPSCO are accepted; (2) allocation of trackers; and (3) Rate 831 implementation.

Mr. Westerhausen summarized that for purposes of settlement, the Rate 831 Settling Parties agreed that NIPSCO's COSS should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 MW allocating approximately $149.438 million (exclusive of approximately $2.827 million in "other revenues") to Rate 831.

Mr. Westerhausen stated that for purposes of settlement, the Rate 831 Settling Parties agree: (1) that Rate 831 Implementation Agreement Exhibit A (which is Attachment 19-R-F to his rebuttal testimony updated for the settlement revenue requirement and the adjustment for Rate 844) will be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms; (2) that Rate 831 Implementation Agreement Exhibit B (which is Attachment 19-R-E to his rebuttal testimony with no changes) sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism; and (3) for the purposes of recovery of any approved capital TDSIC expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load," and TDSIC revenue allocation will only be applied to revenue associated with Rate 831 customers' Tier 1 load. He stated the Rate 831 Settling Parties agreed that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A reflect the allocation factors for TDSIC purposes.

Mr. Westerhausen summarized that for purposes of settlement, the Rate 831 Settling Parties agree that: (1) except as otherwise provided in the Rate 831 Settlement, Rate 831 will be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in the Rate 831 Settlement; (2) the design of Rate 831 will be based on the COSS presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in the Rate 831 Settlement; (3) the "Adjacent Affiliate Qualified Facility Premise Transmission Charge" provision will be amended to be clear that if the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period; (4) the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial five-year contract is as set forth in Rate 831 Implementation Agreement Confidential Exhibit C and agree that Tier 1 subscriptions reflected in Rate 831 Implementation Agreement Confidential Exhibit C will be binding upon each customer in the event of the approval of the Rate 831 Settlement without modification; and (5) a transition period (lasting from the date on which Phase I rates become effective until June 1, 2020) will provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and

capacity needs and agree that applicable terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

Mr. Westerhausen testified that Rate 831 Implementation Agreement Exhibit D sets forth the: (1) Tier 2 and/or Tier 3 contract terms; (2) rate implementation dates; (3) firm capacity transactions under Tiers 2 and 3; and (4) dispute resolution provisions, applicable to the transition period. He stated that the Rate 831 Settling Parties agree that any contract for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions: (1) identify NIPSCO as the Market Participant for the retail customer at MISO; (2) reference NIPSCO's market-based rate authority with FERC; (3) clearly state the Rate 831 customer remains a retail customer of NIPSCO; (4) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations); (5) incorporate relevant provisions of the Rate 831 tariff; (6) all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and (7) any information shared with NIPSCO shall be subject to a confidentiality agreement applicable to all terms of said agreements.

Mr. Westerhausen testified that the Rate 831 Settling Parties agree that the customer's elections under Rate 831 Tiers 2 and/or Tier 3 will occur in a window between the day after NIPSCO's compliance filing in this Cause to 30 days thereafter. He explained that in discussions with NIPSCO, customers recognize that in order to implement Tier 3, customers may need to install software including a security certificate provided by NIPSCO. He noted that the parties agree to work together during the 30-day period to achieve implementation.

Mr. Westerhausen testified that NIPSCO agrees that under either Tier 2 or Tier 3, a customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges.

Mr. Westerhausen testified that NIPSCO agrees that the third-party energy and capacity supplier may represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the Commission. He indicated that at a minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.

Mr. Westerhausen sponsored a redlined tariff that incorporates changes necessary to implement the Rate 831 Settlement as Attachment 19-S2-A.

Mr. Westerhausen testified that if approved, the Rate 831 Settlement assures that if the agreed-upon revenue requirement (as reflected in the Revenue Settlement) and NIPSCO's proposed Rate 831 and cost allocation are approved, there will be no need for a Phase 2 proceeding to establish revised rates. Additionally, Rate 831 Implementation Agreement Exhibit D specifically addresses implementation concerns previously raised by some industrial customers.

B. Industrial Group Witness Phillips. Mr. Phillips presented testimony in support of the 831 Settlement among NIPSCO, the Industrial Group, NLMK, and US Steel. Mr.

Phillips explained that members of the Industrial Group, particularly ArcelorMittal, BP, Cargill, and Praxair, are among the largest of NIPSCO's industrial customers and not only qualify for, but are willing to accept the risk associated with using the proposed service structure under Rate 831.

Mr. Phillips reiterated the importance of establishing appropriate industrial rates as these energy intensive industries continue to face intense domestic and international competition. He stated because of the energy intensive nature of their businesses, energy costs are a major component of the companies' production cost and materially impact economic viability of their operations in NIPSCO's service territory. He stated that approval of the Rate 831 service structure in a form that effectively addresses the issues the rate was intended to address is of significant importance to the Industrial Group. He noted that given the importance of keeping and attracting industrial customers to the overall economic benefit of northwest Indiana, approval of Rate 831 should be of significant importance to all participants in the rate proceeding.

Mr. Phillips testified that the Industrial Group shares the interest in mitigating the rate increases for all customers and therefore was an active and aggressive participant in the negotiations that led to the Revenue Settlement. He noted that settlement reduced NIPSCO's proposed revenue requirement by approximately $63.6 million, which significantly reduced the overall rate increase for all customers.

Mr. Phillips explained that the Rate 831 issues covered in the Implementation Agreement reflect changes in the revenue requirement established by the Revenue Settlement. He added that the Implementation Agreement resolved contested issues regarding the design of Rate 831 and includes the commitment of each Rate 831 customer to take an agreed level of firm service under Tier 1. He added that although the actual level of Tier 1 demand subscribed to by the Rate 831 customers is less than the 194.556 MW that NIPSCO used to allocate cost to Rate 831, the Implementation Agreement provides that the allocation of cost will continue to be based on 194.556 MW. He noted the result of that provision means that the actual rates for Rate 831 will be above cost of service for those customers. Mr. Phillips said that the Implementation Agreement also provides tariff revisions to reflect modifications NIPSCO made on rebuttal or to resolve other issues raised by Rate 831 customers, such as a dispute resolution process, implementation of aggregated metering for adjacent premises, and formulating requirements for third-party contracts.

Mr. Phillips concluded that he recommends approval of the Implementation Agreement because, in his opinion, it significantly reduces the range of issues that would need to be resolved regarding Rate 831, which reduces the need for further litigation on those issues and eliminates the need for a Step 2 true-up process. He concluded the Implementation Agreement establishes Rate 831 in a manner that is workable and fulfills the goals that it was introduced to address.

C. US Steel Witness Georgis. Mr. Georgis testified in support of both the Revenue Requirement and Rate 831 Settlements, noting specifically that the Rate 831 Settlement is premised on the 4CP allocation of production costs because it is appropriate for NIPSCO's summer peaking system and because a 12CP methodology will shift costs into the Rate 831 industrial class, thereby creating even stronger economic signals that make customer self-generation more attractive. Mr. Georgis stated that US Steel's decision to enter into the Rate 831 Settlement is driven by US Steel's analyses of its least cost power options and is an acceptable alternative to NIPSCO's status quo rate structure, which is no longer an economically viable option

for US Steel. Mr. Georgis provided specific details on US Steel's plans to self-build new cogeneration if an economic solution is not achieved.

Mr. Georgis observed that if Rate 831 is not approved or is modified to include additional cost shifts or transition fees, it will be uneconomic for US Steel compared to its cogeneration self-build option. Mr. Georgis testified that in the Rate 831 Settlement, the large industrial customers proactively agreed to commit to a set amount of Tier 1 firm contract demand that fully recovers the required settled revenue requirement for Rate 831 and without such a commitment, the Revenue Settlement as it relates to Rate 831 is meaningless because no customer can be forced to take a set level of firm demand. Mr. Georgis concluded that in addition to being the most economic option for US Steel, the Rate 831 Settlement guarantees that US Steel will remain a customer taking service with a firm contract demand, thereby improving the certainty and future stability of NIPSCO's revenues and rates while US Steel continues to contribute to NIPSCO's fixed cost recovery to the benefit of all customers.

26. Rate 831 Settlement Opposing Testimony.

A. OUCC Witness Boerger. Dr. Boerger filed testimony is response to the Rate 831 Settlement. He supported the OUCC's position that the Rate 831 Settlement should be rejected because it does not address the problems with NIPSCO's original Rate 831 proposal. Dr. Boerger stated that the Rate 831 Settlement does not address, even in part, the cost shift from Rate 831 customers to other rate classes that he identified in his direct testimony. Dr. Boerger addressed the supposed historical "sizable subsidy" argument presented in the Rate 831 Settlement, which appeared to be the basis for not addressing the cost shift to other rate classes. He noted that these large customers cost more to serve than is reflected in traditional cost of service studies, calling into question the existence of such historical subsidies.

Additionally, Dr. Boerger identified other issues of fairness that the Rate 831 Settlement does not adequately address, including the use of a 4CP cost allocation methodology that the Commission has not previously approved for NIPSCO that would further shift costs away from Rate 831 customers. Further, the Rate 831 Settlement, according to Dr. Boerger, would have the Commission accept changes to the AAQFPTC which would cause it to no longer reflect the cost of providing this service, providing further reason to reject the Rate 831 Settlement. Dr. Boerger also stated that the Rate 831 Settlement would not allow the Commission to redesign NIPSCO's proposed transmission charge in a way that would provide correct economic signals for the building of self-generation facilities, as discussed in his direct testimony.

Finally, Dr. Boerger identified an issue discovered in reviewing Rate 831 Settlement documents that carries over from NIPSCO's original proposal for calculating its demand-related cost allocation tracker factors (shown originally in NIPSCO witness Westerhausen's Attachment 19-E). NIPSCO and other settling parties would have a TDSIC-like reduction in cost responsibility applied to non-firm load in spite of a lack of evidence or statutory requirement for making this change, as is the case with TDSIC trackers. Dr. Boerger concluded that this proposed allocation methodology would result in Rate 831 customers being allocated too little revenue requirement and other rate classes too much revenue requirement, and he recommended that NIPSCO be required to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1

Adjustment shown in Implementation Agreement Exhibit A and in Attachment 19-E of Mr. Westerhausen's prefiled direct testimony.

B. CAC Witness Olson. Mr. Olson offered testimony in response to the Rate 831 Settlement. He sponsored transcripts from the public field hearing, highlighting testimony from many of the speakers, including the Michigan City Council President, local business owners, and residential customers. He spoke about several local ordinances and resolutions passed by municipal governments located in NIPSCO's service territory, which reference the initial request for an approximate 12% increase for residential customers. Mr. Olson stated that all members of the rate-paying public have an interest in achieving a fair and balanced outcome, but the parties to the 831 Settlement are its only beneficiaries. Mr. Olson concluded that the Commission should reject NIPSCO's proposal for industrial restructuring and reject the proposed Rate 831 Settlement.

C. CAC Witness Wallach. Mr. Wallach testified the Rate 831 Settlement would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes and would allocate those costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand, not contract demand. He stated that the proposed allocation of revenues to the Rate 831 class would recover from large industrial customers less than their fair share of embedded production costs and would instead unfairly and unreasonably shift recovery of such costs to other rate classes. Specifically, he estimated that the Rate 831 Settlement's revenue allocation would shift recovery of about $66 million of annual non-fuel revenue requirements from industrial customers to other customers, assuming a 4CP allocator is used. If demand-related production costs were allocated using a 12CP allocator, as the OUCC recommends, then Mr. Wallach estimated the proposed Rate 831 Settlement would shift recovery of about $94 million of annual non-fuel revenue requirements from industrial customers to other customers.

Mr. Wallach recommended the Commission reject the Rate 831 Settlement and deny NIPSCO's request for an ARP as not in the public interest. Instead, he recommended that the current industrial service structure be retained and that a procedural schedule be established to determine the appropriate revenue allocation and rate design for all rate classes.

Mr. Wallach testified there is a risk of a loss of industrial load, with its attendant cost-shifting, if the Commission decides to retain the current industrial service structure; however, neither NIPSCO nor any of the other Rate 831 Settling Parties provided any evidence that the potential load loss under the current service structure would exceed the current load loss under the proposed Rate 831 structure. Thus, he said, the Rate 831 Settling Parties failed to show that other customers would be worse off under the current service structure than under the Rate 831 structure. Instead, the Rate 831 Settling Parties would have the Commission approve a radical change in the industrial service structure based on speculation that the potential margin loss with the current structure could be even greater than the demonstrated loss under the Rate 831 structure.

27. Rate 831 Settlement Reply Testimony.

A. NIPSCO Witness Kelly. Mr. Kelly made clear that in the event the Commission rejects the Rate 831 Settlement, as suggested by both OUCC witness Boerger and CAC witness Wallach, the revenue requirement would need to be changed to remove adjustments

that were made to effectuate the ARP, including updating load research for historical demand to reflect firm demand for Rate 831 customers under existing Rates 732, 733, and 734; addressing the treatment of MISO charges and revenues that have been proposed to be removed from base rates; making adjustments to reflect aggregation that would migrate customer premises among Rates 724, 732, and 733; and addressing Rider 776 Back-up, Maintenance, and Temporary Service revenues and OSS activities.

Mr. Kelly also noted that the assumption that US Steel's demand under Rates 732 and 733 would be similar to that projected under Rate 831 is incorrect because no additional interruptible service is available under Rider 775. As such, the firm amount would need to remain at a level consistent with today's 700 Series rate structure, under Rate 831, except for the adjustment for aggregating multiple premises currently served under Rates 732 and 733.

Mr. Kelly pointed out that no evidence has been provided to show that an across-the-board rate increase as suggested by OUCC witness Boerger utilizing existing Rates 732, 733, and 734, would result in rates that were just and reasonable.

Mr. Kelly raised concern that the testimony of witnesses Boerger, Wallach, and Olson (and others) attacks the prudence of Rate 831 by fixating on the near-term impacts to other rate classes without recognizing the substantial long-term risks that are in play with this decision. He testified that what is being characterized as an industrial subsidy for Rate 831 customers is a misnomer and ignores the fact that Rate 831 is a fully costed rate designed at parity. He emphasized that NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers as it addresses its aging coal generation fleet and navigates a dynamic economic environment. Mr. Kelly opined that it is undeniable that the Rate 831 proposal will assign more of NIPSCO's production costs to other customer classes, which will produce higher rates in the near term than they would otherwise pay absent the restructuring of large industrial rates. He asserted that the long-term risk is garnering little attention and that these large industrial customers already have options for significantly reducing their firm requirements and are poising themselves to implement those options if Rate 831 is not approved.

Mr. Kelly testified that if Rate 831 is not approved according to the terms of the Rate 831 Settlement, he is convinced that at least some of these customers are going to make the incremental investments to leave the NIPSCO system, or worse, will shift industrial production away from NIPSCO's service territory. He stated that when that occurs, NIPSCO will need to file multiple rate cases as chunks of firm load leave its system, and those rate cases are going to propose to reallocate the unrecovered fixed costs left behind by these customers from the remaining customer classes. He testified that while witnesses in this case are focusing on the fairness of a cost shift within this rate case of approximately $40 million to $66 million between Rate 831 and other classes, if NIPSCO does not move to the Rate 831 structure now, it will be talking about another $100 million to $150 million of unrecovered costs that would have been collected under Rate 831 but will be left behind as these customers further bypass NIPSCO's service. That is not to say that $40 to $66 million dollars is an insignificant issue or that NIPSCO does not care about the near-term impact to its other customers classes, but when NIPSCO considered the full range of impacts in play rather than just the near-term cost shift, it was apparent that Rate 831 is the right solution now rather than later. Mr. Kelly restated that attempting to retain the current service structure is

only going to increase the risk that these customers will exercise their options to cogenerate additional power or relocate production to avoid an increasing NIPSCO electric price.

Mr. Kelly stated that he is concerned because the arguments being raised attempt to mute NIPSCO's interest in representing its other customer classes in the Rate 831 proposal. He noted that it is atypical for a vertically integrated utility to propose allowing a significant portion of its load to have the ability to procure capacity and energy from wholesale market suppliers; in fact, that cuts directly against the profit motive of an investor-owned utility. He asserted that NIPSCO is considering the interest of all of its customers and stakeholders as it moves through this transitional time.

Mr. Kelly testified that the Rate 831 proposal would reduce NIPSCO's long-term business opportunity as an investor-owned utility because it is downsizing the amount of firm load that NIPSCO is obligated to serve for at least five years thereby reducing the amount of MW that NIPSCO has the right under Indiana law to serve under its monopoly charter. He stated that the reason NIPSCO is making this proposal, however, is because it is the best outcome that could be identified for all of its customers, employees, investors, and stakeholders given the parameters that NIPSCO faces at this time of sustained low natural gas prices, historically lower cost of capital, aged coal-fired generation, aging boiler systems within customer plants creating a cogeneration opportunity when replacing, large sophisticated energy users, strong economic conditions, etc. Mr. Kelly testified that this decision was not reached lightly, and NIPSCO did not craft it alone for its benefit. His ultimate concern is that NIPSCO is going to miss out on reaching a sustainable path forward where these customers keep paying a sizeable portion of their costs because there is a lot of volume on the near-term portion of the analysis without considering the substantially larger risk around the long-term portions.

In response to CAC witness Olson's testimony objecting to a 12% rate increase for those other rate classes, Mr. Kelly pointed out that the 12% figure is the result from NIPSCO's original proposal as filed. He pointed out that if the Commission approves both the Rate 831 Settlement and the Revenue Settlement, the resulting change in rates for all other customers (other than Rate 831) would be 6.66%.

Finally, Mr. Kelly pointed out the consequences of rejecting the Rate 831 Settlement. He explained that as NIPSCO begins to implement the results of its IRP and procure replacement capacity that will live on for decades, NIPSCO needs to ensure some stability in what its obligation to serve will be for its largest industrial loads. He stated that retaining the current industrial service structure will only increase the risk that NIPSCO's industrial load will further decline over time and create unrecovered costs on the way down. Mr. Kelly testified that without approval of the Rate 831 industrial service structure, NIPSCO would be put into a position of modifying its existing Rate 732, 733, and 734 service structure to re-integrate the Rate 831 customers, which is no small task. He explained that as part of that process, to retain some of the assurances of stability in the near term, NIPSCO would likely seek to modify parts of the existing Rate 732, 733, and 734 industrial service structure such as changing contract terms, altering Rider 775 registrations, and restructuring NIPSCO's back-up and maintenance service. He noted that these steps do not actually reduce the risk industrial customers will exercise their options in the future, and may in fact increase that chance.

B. Industrial Group Witness Phillips. Mr. Phillips presented settlement reply testimony in response to the OUCC witness Boerger and CAC witness Wallach. In response to the OUCC and CAC witnesses' assertion that the Implementation Agreement unfairly shifts rate recovery of NIPSCO's legacy production costs to other customer classes, Mr. Phillips testified that for many decades the industrial classes have paid above-cost rates in order to subsidize residential customers. Mr. Phillips discussed the Commission orders describing the inter-class subsidies that industrial classes have provided to other customers. Mr. Phillips also stated that over the last two rate cases, industrial rate increases have totaled more than 22%. Mr. Phillips quantified the magnitude of the rate subsidies paid over the years by the industrial classes as being in the range of $1.4 billion to $2.85 billion, which are substantially greater than the legacy cost that Dr. Boerger and Mr. Wallace contend the large industrials would avoid under the Implementation Agreement. He stated that it is clear that the industrial classes have already provided rate revenue far in excess of their cost-based share of NIPSCO's legacy production cost and that essentially the OUCC and CAC are advocating for continuing and increasing the subsidies paid by industrial customers.

Mr. Phillips took issue with Dr. Boerger's theory that a need for rate mitigation does not necessarily imply the presence of a subsidy and that industrial customers should have paid higher returns in the past. Mr. Phillips first noted that it is clear residential customers have been subsidized for a number of years as detailed in Commission orders as far back as 1981. Mr. Phillips also noted that in the current case, even under the OUCC's preferred cost methodologies, the residential class would still be receiving a subsidy. He added that if all subsidies were eliminated and a 12CP allocation method were used, the residential class would see a rate increase of 17.4% rather than the 6.66% provided for in the Revenue Settlement agreement and the Implementation Agreement. He stated that questioning the residential rate subsidy amounts to disagreeing with both a consistent line of Commission orders and the OUCC's own cost of service proposal.

Mr. Phillips also testified that Dr. Boerger's theory that industrial customers should have been paying a higher rate of return had never been addressed in NIPSCO's past rate cases or in any of the cost allocation methodologies the OUCC has proposed. He added that the alleged risk suggests volatility in the industrial load in contrast to what Dr. Boerger described as the more stable residential service, but in fact the residential load is much more volatile due to seasonal swings than the high load factor industrial customers Dr. Boerger referenced. Therefore, Mr. Phillips stated it is misguided to attempt to reinterpret past orders based on a nonstandard theory that was not raised previously and rests on a faulty rationale.

Mr. Phillips testified that the Implementation Agreement locks in cost recovery from Rate 831 customers based on 194.556 MW of firm demand under five-year contracts, which allows NIPSCO to retain firm load in the face of the risk that industrial usage on the system would continue to decline. In response to the OUCC and CAC witnesses' contention that the risk of the loss of industrial load does not justify the approval of the Implementation Agreement, Mr. Phillips testified that the risk of additional loss of load is immediate and substantial. He pointed to BP's self-supply arrangement and US Steel's potential additional cogeneration project if Rate 831 is not approved. He added that ArcelorMittal has already reduced load served by NIPSCO by 50% since 2011 due to closing facilities and generating more power internally in response to NIPSCO's rates. He stated there is continuing pressure to cut NIPSCO's load by shifting production to other locations or increasing internal generation because costs are consistently higher in locations served by NIPSCO than in other ArcelorMittal facilities. He added that Praxair is evaluating significant

self-generation projects. Mr. Phillips testified that absent the revenue stability provided by Rate 831, NIPSCO faces continued loss of industrial load, which would lead to a cycle of rate cases that would result in further increases making NIPSCO's service less viable for industrial customers.

Mr. Phillips explained that the Implementation Agreement would provide full cost recovery of system costs for the firm load being served under Tier 1, including the cost associated with legacy production assets and depreciation expenses relating to planned retirements. He added NIPSCO will continue to collect transmission revenue from Rate 831 customers on their non-firm load under Tier 2 and 3 as well as under Tier 1. Mr. Phillips also noted that the contractual commitments under the Implementation Agreement will provide NIPSCO with a more reliable projection of capacity needs and facilitate a more orderly transition to a new resource portfolio.

Mr. Phillips stated that the alleged cost shift and Rate 831 subsidy are both inaccurately described and incorrectly computed. He noted that the OUCC and CAC witnesses treat Rate 831 as if it were a rate decrease instead of a revenue reduction aligned with the decreased use of NIPSCO's assets. He added that Mr. Wallach's computation improperly allocates production cost to interruptible load, which is contrary to cost of service principles. Mr. Phillips referred to his cross-answering testimony relating to the flaws in Mr. Wallach's computation and also explained that the studies provided in response to CAC data request 11-001(b) and (c) are flawed for the same reasons. Mr. Phillips explained that allocating generation investment to interruptible load and then subtracting revenue credits does not fix the erroneous allocation of production cost. He stated that subtracting revenue credits reduces the rate of return of those particular rate classes, which creates the opposite effect of fixing the erroneous allocation of costs. He added that the revenue credits do not equal the generation cost erroneously being allocated to interruptible load because the revenue credits are less than the generation cost being allocated. Mr. Phillips also stated that Mr. Wallach only used $42.6M in revenue credits, which was less than the credits actually paid. He added there are other issues with the Rates 732, 733, and 734 COSS Mr. Wallach relied upon because it includes different riders than the 800 series would have under NIPSCO's proposal. The revenue requirements and fuel costs used were larger than used for settlement, the removal of the BP load may be inconsistent with NIPSCO's treatment of the removal in the COSS in this case, and the study fails to normalize the 2017 loads for allocation.

Mr. Phillips also disagreed with Mr. Wallach's assertion that the aggregation of metering for BP and WCE would result in a cost shift and provide a subsidy to industrial customers. He noted that self-supply arrangements are expressly encouraged as a matter of public policy under Indiana and federal law and that BP's use of privately owned generation assets to supply power to itself results in a decrease in the electric service from NIPSCO. Consequently, NIPSCO will collect less revenue from BP because it will sell less power to BP. Mr. Phillips stated that is no more of a cost shift than any change in demand between rate cases and does not establish any subsidy that industrial customers will enjoy at the expense of other rate classes.

In response to the OUCC and CAC witnesses' arguments that the industrial customers should be required to provide a higher level of cost recovery for NIPSCO's legacy production assets, Mr. Phillips explained that the Commission has consistently recognized that interruptible service enables NIPSCO to avoid building generation capacity to serve that load to the benefit of all ratepayers. In addition, NIPSCO's largest industrial customers have invested in private generation assets, which reduces the incremental load that NIPSCO had to build and maintain

generation capacity to serve. He said that if NIPSCO had been required to build additional capacity to serve the interruptible load and the self-supplied load as firm demand, the magnitude of unrecovered cost for legacy production assets would be much greater than it is currently. Consequently, Mr. Phillips stated that the large industrial customers have mitigated the magnitude of the legacy costs through their interruptible service and self-supply arrangements and have also paid their allocated share for the bulk of NIPSCO's historical investments in coal-fired generating units, while providing massive rate subsidies to residential customers over that same period.

Mr. Phillips also noted that the large industrial load serviced by NIPSCO today is a very different set of customers from those on the system when the legacy production investments were made. He testified there is no expectation that the prior customers would be obligated to continue providing cost recovery 40-50 years into the future and that subsequent customers would take on that obligation.

In response to the OUCC's and CAC's criticism of the Implementation Agreement providing for a 4CP allocation, Mr. Phillips said that NIPSCO had proposed the 4CP method in its original filing, that the industrial parties had filed testimony supporting that allocation, that the 4CP method is consistent with how NIPSCO designs and operates its system and represents sound ratemaking. He also explained that the Implementation Agreement, by locking in firm Tier 1 demand commitments, eliminates the need for a second phase.

In response to Dr. Boerger's suggestion that Tier 1 commitments could be filed as a standalone without predetermining other issues, Mr. Phillips explained that Rate 831 customers cannot commit to a level of firm demand without knowing what the rates would be. Mr. Phillips testified that the Implementation Agreement provides significant value that had not previously been established. He noted that the possibility material changes to Rate 831 could lead to withdrawal of the proposal has been present throughout the case and not introduced for the first time by the Implementation Agreement.

Mr. Phillips also addressed Dr. Boerger's arguments regarding NIPSCO's tracker allocations. Mr. Phillips testified NIPSCO has not changed the proposed allocation from its case-in-chief; all the Implementation Agreement does is update the agreed reduction in revenue requirements. He noted that Dr. Boerger did not raise any objection to the proposed allocation in his direct testimony. Mr. Phillips added that allocating the demand allocators on firm demand is appropriate for the same reasons allocating base rate costs only on firm load is appropriate. The Rate 831 customers' Tier 2 and 3 loads will not be served using NIPSCO's production resources and therefore should not have trackers allocated on that load.

As to Dr. Boerger's objection to the revision of the adjacent customer facilities, Mr. Phillips explained that the proposed change was to resolve a longstanding dispute between NIPSCO and one of its large customers. He said the change maintains the status quo for the facilities at issue in Cause No. 45078 by determining the amount of energy subject to the transmission charge on a monthly basis.

C. US Steel Witness Georgis. Mr. Georgis addressed the OUCC's and CAC's Rate 831 Settlement opposition. Mr. Georgis testified that the Rate 831 Settlement preserves the fundamental rate and structure of Rate 831 and fully recovers the settled revenue requirement

associated with the large industrial class. Mr. Georgis observed that under the Rate 831 Settlement, large industrial customers proactively agreed to commit to a set amount of Tier 1 Firm Contract Demand elections and a demand rate that fully recovers the required settled revenue requirement for the 831 rate class. He noted that without such a commitment, the Revenue Settlement as it relates to Rate 831 is meaningless because no customer can be forced, either by NIPSCO or the Commission, to take a set level of firm demand. He testified that the Rate 831 firm Tier 1 service offering is similar to the status quo, in that NIPSCO and its large industrial customers currently have contracts under the existing Commission-approved interruptible rate structure that commits those customers to a certain level of firm service.

Mr. Georgis disagreed with Dr. Boerger's distinction between mitigation and subsidy, noting that the terms go hand in hand. He observed that if there is no subsidy in the rate structure, there is no need for mitigation, but as the Rate 831 Settlement notes, there is a sizable subsidy in NIPSCO's residential rates. Mr. Georgis concluded that if Rate 811 is not paying its cost of service, it is being subsidized. He stated that in addition to the subsidy in the settled revenue requirement, Rate 831 is further subsidizing other customer classes based on the transmission portion of the ACOSS. He noted that five of the large industrial customers are paying $17 million more than their cost of service for transmission and subsidizing the transmission costs of other customer classes. He noted that a sixth customer will only increase this level of transmission subsidy, which was ignored by the OUCC. Mr. Georgis testified that the Commission should not look at Rate 831 in isolation and ignore years of subsidization by large industrial customers to the benefit of other customer classes. He stated that without the approval of Rate 831, upward movement in NIPSCO's rates and sustained subsidization will cause the continued bypass of NIPSCO's system by large industrial customers.

Mr. Georgis refuted Dr. Boerger's claim that industrial customers are more risky and presumably should be allocated additional costs. He noted that for years, Rate 831 customers have paid a subsidy and premium. He testified that NIPSCO's rates are already too high and are not competitive, which is why US Steel's existing cogeneration is beneficial and future cogeneration is still a possibility if Rate 831 is not approved. He also stated that increased rates for large industrial customers will exacerbate the departure of industrial load, which increases rate volatility and risk for other customer classes. Mr. Georgis testified that the OUCC's proposal amplifies the existing uncompetitive rate environment rather than creating the competitive, cost-based solution that Rate 831 provides while helping to ensure that large industrial customers commit to staying on NIPSCO's system and pay a cost-based share of system costs.

Mr. Georgis also refuted Dr. Boerger's claims that the loss of additional US Steel load if Rate 831 is not approved would be modest. He noted that it is important to look at the financial impact of the US Steel load within the context of the position that the OUCC is taking on Rate 831. Under Rate 831, he explained that large industrial customers have a combined firm revenue allocation of $149.438 million. While not indicative of any one particular customer's share, he testified that on average, there is a $24.9 million contribution to the revenue requirement for each of the six large industrial customers, which is more than the $20 million lower end of the OUCC's alleged Rate 831 "cost shift" range. Mr. Georgis testified that these demand costs would shift to other customers if US Steel installed additional cogeneration and took additional firm load off of NIPSCO's system. Mr. Georgis concluded that the financial impact of just one large industrial

customer leaving NIPSCO's system is well within the range of the $20 million to $40 million in "cost shifting" that the OUCC argues exists under Rate 831.

Mr. Georgis also refuted Dr. Boerger's claim that the Rate 831 AAQFPTC is unreasonable. He noted that Rate 831 already overpays on transmission relative to NIPSCO's cost of service, so increasing the AAQFPTC exacerbates that problem. He testified that while NIPSCO refined the inputs, the methodology for calculating the AAQFPTC remains the same as originally proposed and accurately reflects the impacts of both settlements.

In response to Dr. Boerger's recommendation that NIPSCO recalculate its demand allocation tracker allocators to eliminate the Rate 831 Tier 1 adjustment, Mr. Georgis testified that these tracker costs are only applicable to NIPSCO full requirements customers or portions of customers' loads that are full requirements service. He explained that Rate 831 Tier 1 service is full requirements service, while Tier 2 and 3 are not. Mr. Georgis stated that the Demand Allocation referenced by Dr. Boerger is used for the RTO and FMCA riders, but these riders are not applicable to Tiers 2 and 3 because Rate 831 customers are buying energy in the wholesale market. Mr. Georgis testified that large industrial customers should not pay NIPSCO's system costs covered by these riders because they are not using NIPSCO's system under the market-based rate concept. He stated that the only part of NIPSCO's system that US Steel will use is bulk transmission, and those transmission costs are appropriately recovered under the Rate 831 tariff.

Mr. Georgis noted several practical problems with Dr. Boerger's suggestion that if Rate 831 is not approved, the Commission can address large industrial rates in a Phase 2 proceeding setting rates based on the existing 700 series rate design. First, he testified that eliminating the proposed and settled rate design of the largest load on NIPSCO's system that ensures full cost recovery and replacing it at a later date while all other elements of NIPSCO's rate structure remain static leads to significant uncertainty and potential volatility. Second, such a result would not allow Rate 831 customers proper time to plan and evaluate customer and bill impacts and implications of the rates. Finally, he stated the current and proposed rate structures are not an "apples to apples" comparison, and the rates should not be delayed and potentially replaced in this way.

Mr. Georgis testified that under the Rate 831 Settlement, US Steel has agreed to accept a rate design that it still believes, at least in part, contains subsidies. He noted that to request those subsidies continue in another form or alternative rates that provide none of the benefits of Rate 831 is neither fair nor equitable. Mr. Georgis observed that none of the large industrial customers qualify under any other of NIPSCO's proposed rate classes, and NIPSCO has not presented any form or pricing of an interruptible credit in this proceeding, which is a key element of the existing 700 series rates. Mr. Georgis concluded that in the event Rate 831 is not approved, customers should be permitted to revisit arguments regarding the full access, functionalization, and allocation of costs so that they have a fair opportunity to present evidence to the Commission regarding proper rate design for all customers.

Mr. Georgis testified that CAC's witnesses mischaracterize Rate 831 as a subsidy to industrial customers. Mr. Georgis emphasized while large industrial customers' rate revenues are decreasing from current levels, this is largely because their rates reflect the true cost of service since they are no longer procuring the vast majority of their power from NIPSCO. Mr. Georgis testified that under Rate 831 large industrial customers still must pay to cover their load, either via

the market pass-through rates under Tier 2, or to a third party under Tier 3. He also noted that while Rate 831 customers have the opportunity to benefit from the market, they are also taking on risk. He concluded that Rate 831 is simply not a "guaranteed win" for large industrial customers, nor is it a guaranteed rate savings. Instead, Mr. Georgis testified that Rate 831 is a regulatory solution to the problem of NIPSCO's continued load loss and provides an economic alternative for some of the largest companies in Indiana to remain customers of NIPSCO.

28. Commission Discussion and Findings.

A. Settlement. Settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coal. of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.*, 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. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Pub. Serv. Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Revenue Settlement or Rate 831 Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Revenue Settlement and Rate 831 Settlement are reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such agreements serve the public interest.

Our review of the reasonableness of the Revenue Settlement and Rate 831 Settlement is aided by the comprehensive scope of the Revenue Settling Parties' and Rate 831 Settling Parties' agreements as well as the extensive evidence of record that addresses competing positions on a wide range of issues, including: (1) the cost of common equity; (2) calculation of NIPSCO's capital structure; and (3) the financial basis for results at present, proposed, and settlement rates. Each of these issues was addressed in testimony that considered a range of proposed outcomes. The evidentiary record provides a thorough consideration of the merits of the issues presented, thereby affording the Commission with a detailed record from which to make findings and conclusions.

We first address the Rate 831 Settlement and then the Revenue Settlement, which is impacted by our decision on the Rate 831 Settlement.

B. Rate 831 Settlement. In reviewing NIPSCO's proposed Rate 831 industrial service structure and the Rate 831 Settlement, we first recognize that NIPSCO's system is uniquely situated from other Indiana electric utilities. Industrial customers comprise less than 1% of total NIPSCO customers but account for more than 56% of its energy sales, and NIPSCO's five largest customers reflect 40% of NIPSCO's load. This large concentration of load in a few specific customers presents a distinct business risk for NIPSCO. This risk is heightened by the fact that these customers are mostly large, sophisticated energy users competing in global and domestic

markets characterized by sustained low natural gas prices and historically low cost of capital. These factors further incent industrial customers to utilize new or existing self-generation facilities to wholly or partially serve their energy needs.

Over the years, the Commission has found it to be in the public interest for NIPSCO to utilize the interruptible service characteristics of its large industrial customers. In Cause No. 43969, NIPSCO expanded its long-standing use of interruptible service to be integrated into the evolving MISO market. In Cause No. 43969, seven customer premises took service subject to Rider 675, and NIPSCO's capacity requirements in the MISO market were reduced by approximately 377 MW. In Cause No. 44688, we approved NIPSCO's proposed expansion of the availability of the interruptible rate at the request of its industrial customers. This expansion of interruptible load in turn allowed NIPSCO to reduce its capacity requirements by approximately 530 MW to the benefit of all customer classes. Given this context, NIPSCO developed its proposed Rate 831 industrial service structure as an evolution of its current interruptible service option approved by the Commission in NIPSCO's last two rate case orders.

In its Petition, NIPSCO requested that the Commission approve its proposal for a new industrial service structure as an ARP. NIPSCO elected, pursuant to Ind. Code § 8-1-2.5-4, to become subject to the provisions of Ind. Code § 8-1-2.5-6 for this purpose, and requests that the proposed industrial service structure be found to be in the public interest pursuant to Ind. Code § 8-1-2.5-6. The Rate 831 Settlement modifies, and provides the means to implement, the proposed ARP. As such, we assess the Rate 831 Settlement as an ARP under the provisions of the ARP Statute.

The legislative policy set forth in Section 1 of the ARP Statute anticipates the implementation of flexible alternatives to traditional regulatory practices and structures, and recognizes that amidst a changing energy environment, such flexibility is "essential to the well-being of the state, its economy, and its citizens." Moreover, pursuant to Ind. Code § 8-1-2.5-1(6), we are specifically authorized to implement such flexible alternatives.

NIPSCO seeks approval of the Rate 831 industrial service structure under Ind. Code § 8-1-2.5-6, which provides:

> (a) Notwithstanding any other law or rule adopted by the commission, except those cited, or rules adopted that pertain to those cited, in section 11 of this chapter, in approving retail energy services or establishing just and reasonable rates and charges, or both for an energy utility electing to become subject to this section, the commission may do the following:
>
> > (1) Adopt alternative regulatory practices, procedures, and mechanisms, and establish rates and charges that:
> >
> > > (A) are in the public interest as determined by consideration of the factors described in section 5 of this chapter; and
> > >
> > > (B) enhance or maintain the value of the energy utility's retail energy services or property;

including practices, procedures, and mechanisms focusing on the price, quality, reliability, and efficiency of the service provided by the energy utility.

(2) Establish rates and charges based on market or average prices, price caps, index based prices, and prices that:

(A) use performance based rewards or penalties, either related to or unrelated to the energy utility's return or property; and

(B) are designed to promote efficiency in the rendering of retail energy services.

We may approve, reject, or modify the plan; however we may not make material modifications without NIPSCO's consent. Ind. Code § 8-1-2.5-6(d). In evaluating an ARP submitted under Ind. Code § 8-1-2.5-6, we are directed by Ind. Code § 8-1-2.5-6(a)(1)(A) to make a public interest finding "as determined by consideration of the factors described in section 5 of this chapter." Therefore, in determining whether the public interest will be served by this limited declination of jurisdiction, Ind. Code § 8-1-2.5-5(b) requires that we consider the following:

1. Whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;

2. Whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;

3. Whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency; and

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

It is against these statutory criteria, and in light of the legislative policy set out in Ind. Code § 8-1-2.5-1, that we evaluate NIPSCO's request to approve its ARP seeking to establish the proposed industrial service structure as implemented through the Rate 831 Settlement.

As we consider the first factor, there is ample evidence in the record that changes in the technology, operational conditions, and competitive forces support approval of the Rate 831 Settlement. It is uncontroverted that NIPSCO's large industrial customers utilize energy intensive processes and are sophisticated market participants competing on the basis of price globally. Given this competitive marketplace and the ability of NIPSCO's large industrial customers to reduce their demand on NIPSCO's system through self-generation or relocation, we agree with NIPSCO and find that now is the time to address the risks presented by its large industrial customers as NIPSCO simultaneously addresses its on-going generation needs. Service under Tiers 2 and 3 of Rate 831 will be set by competitive forces administered by MISO under FERC jurisdiction. Furthermore, NIPSCO's proposal requires its largest industrial customers to remain as its retail customers, while at the same time providing more market choices. The Commission has considered the evidence presented and finds that the Rate 831 Settlement meets this first factor.

Regarding the second factor, the evidence supports the conclusion that approval of the Rate 831 Settlement will benefit the energy utility, its customers, and the state. The evidence shows that NIPSCO has already lost a significant amount of its industrial load due to customer self-generation and customers shifting or closing production. Furthermore, the evidence demonstrates that NIPSCO is at risk of losing more industrial load in the absence of a change in service structure to better align industrial rates with cost of service.

Assessing the severity of the risks of large industrial bypass requires informed judgment. The record shows that NIPSCO has closely examined the global trends affecting its steel-making and other largest loads as well as facility-specific actions that are under consideration. Based on this analysis, NIPSCO has proposed Rate 831 to ameliorate the substantial threat posed by potential industrial load loss. The record shows that approval of Rate 831 would reduce NIPSCO's long-term business risk because the amount of firm load it is obligated to serve for at least five years would be more certain. We find the record describing BP's actions to self-serve its load, the testimony detailing the planned or potential actions by US Steel and Praxair, and the significant reduction of ArcelorMittal load to be persuasive evidence warranting a proactive response by NIPSCO.

The Commission understands that the OUCC and CAC opposed approval of the Rate 831 Settlement and considered their arguments that the Rate 831 Settlement: (1) avoids NIPSCO's legacy cost burden by passing it on to other rate classes; (2) implements a cost allocation methodology unfair to other rate classes; (3) eliminates the opportunity to ensure the transmission charge for backing up self-generation reflects the cost of service; and (4) modifies NIPSCO's proposed adjacent facilities transmission charge such that it no longer reflects cost of service. The OUCC also recommended the Commission require NIPSCO to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1 Adjustment in Exhibit A to the Rate 831 Settlement. The CAC argued that the Rate 831 Settlement is not in the public interest because it would unduly subsidize large industrial customers by shifting recovery of embedded production costs to other rate classes and by allocating those costs to large industrial customers on the basis of contract demand rather than total demand, even though such production costs were incurred in the past to serve total demand.

By analyzing the prudence of Rate 831 through a fixation on the near-term impacts to other rate classes, the OUCC, CAC, and other parties fail to recognize the substantial long-term risks addressed by this decision. What these parties qualify as a subsidy for Rate 831 customers is a mischaracterization that ignores the fact that Rate 831 is a fully costed rate designed at parity. NIPSCO proposed Rate 831 to facilitate an orderly transition for all of its customers while addressing its aging generation and navigating a dynamic economic environment. Although the Rate 831 proposal requires NIPSCO's other customer classes to pay higher rates in the near term than they are currently paying today under the existing service structure, the long-term risk is that these large industrial customers will otherwise exercise their options to significantly shift load off NIPSCO's system. When that occurs, costs might reasonably be reallocated to the remaining customer classes. While the OUCC and CAC focused on the fairness of a cost shift within this rate case between Rate 831 and other classes, the record shows that denying Rate 831 now would likely result in even higher costs, which would otherwise have been collected under Rate 831 if these customers further bypass NIPSCO's service. When considering the full range of impacts in play

rather than just the near-term cost shift, Rate 831 is a reasonable solution now rather than later. We find that retaining the current service structure would only increase the risk that these customers will exercise their options to self-generate additional power or relocate production to avoid an increasing NIPSCO electric price.

Given that large industrial customers constitute such a significant portion of NIPSCO's retail electric sales, reducing their load would cause precipitous declines in NIPSCO's revenues and operating margins far faster than could be offset by growth in other sectors. In the long run, we find that such load loss would subject remaining customers and customer classes to increased costs above and beyond the near term costs of the Rate 831 Settlement. Conversely, we find that approval of this new service structure will provide Rate 831 customers increased flexibility to meet their electricity requirements and improve their ability to compete in global markets while other customers and the utility benefit from reduced risks and greater certainty in large industrial load for a set period of time.

For the foregoing reasons, we find the Rate 831 Settlement is a reasonable proposition to retain industrial load, and its approval is beneficial to NIPSCO and all of its customers. As such, the Rate 831 Settlement satisfies the second factor.

The Commission finds that the Rate 831 Settlement also meets the third factor by promoting utility efficiency. In particular, Rate 831 reduces the amount of replacement capacity NIPSCO must plan for, provides more reliable load projections for planning purposes, and mitigates the risk of building excess capacity.

As NIPSCO begins to implement the results of its IRP and procure replacement capacity, NIPSCO needs to ensure some stability in what its obligation to serve will be for its largest industrial loads. Rejecting Rate 831 and retaining the current industrial service structure would only increase the risk that NIPSCO's industrial load will further decline over time thereby creating unrecovered costs. NIPSCO would simultaneously be forced to modify its existing Rate 732, 733, and 734 service structure to re-integrate the Rate 831 customers. In that alternative, NIPSCO would likely seek to modify the existing Rate 732, 733, and 734 industrial service structure, alter Rider 775 registrations, and restructure NIPSCO's back-up and maintenance service. These hypothetical proposals to attain some near-term load stability would not actually reduce the risk that industrial customers will exercise their options in the future. We find that approval of the Rate 831 Settlement would demonstrably improve NIPSCO's ability to forecast the load it is required to serve and would thereby enhance its accuracy in procuring the appropriate amount of replacement capacity for its aging generation resources. Likewise, approval of the Rate 831 Settlement will also enable NIPSCO to make better resource decisions while maintaining system reliability and resiliency. As such, we find that the Rate 831 Settlement satisfies the third factor by promoting utility efficiency through more accurate load forecasts and corresponding capacity procurement.

Finally, regarding the fourth factor, a review of the evidence shows that, without the approval of the Rate 831 Settlement, NIPSCO will be hindered in its ability to compete with alternative sources of energy supply and risks further migration of load from its largest industrial customers.

Based on the evidence, we find that NIPSCO is facing the prospect of retiring aging generation resources and procuring replacement capacity in the near term. Despite current strong economic conditions, NIPSCO Electric operations continue to face declining industrial usage driven by the development of customer-sited generation and uncertainty in some global industrial markets. We find that the electric industry is in the midst of a transformation, and it is crucial that NIPSCO be in a position to flexibly align with this transformation.

In past orders, NIPSCO has been permitted to allow its large industrial customers to assume more market risk through the use of interruptible service offerings. The new industrial service structure is the next step in this evolutionary process. 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 Rate 831 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. We find that if 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 are low.

Based on this evidence and the findings made above, the Commission finds that the Rate 831 Settlement meets the fourth factor and that NIPSCO's proposed ARP, as embodied in the Rate 831 Settlement, is in the public interest.

The Commission has considered the Section 5(b) factors and the evidence, and we find that they support approval of NIPSCO's proposed ARP. We find the proposed ARP and Rate 831 Settlement are consistent with the legislative policy set forth in Ind. Code § 8-1-2.5-1. We are mindful of NIPSCO's unique reliance on a small number of very large industrial loads that are subject to intense global competitive pressures. We find that technological conditions and competitive forces are rendering traditional regulation over NIPSCO's industrial service structure less efficient and potentially more costly because, if a change is not made, more industrial load is reasonably expected to leave the system of customers supporting NIPSCO's retail service cost thereby creating future cost-recovery risks. It is not in the public interest to ignore the challenges of NIPSCO's traditional rate structure in the face of demonstrated and probable industrial load loss, and we are not inclined to adopt a purely reactive approach. By declining to exercise our traditional jurisdiction and embracing the alternative structure that is captured in the Rate 831 Settlement, we find that NIPSCO, all of its customers, and the State should benefit by preserving a defined level of firm large industrial load and avoiding the effects of stranded cost that might reasonably otherwise occur. In so doing, we promote energy utility efficiency by allowing NIPSCO to better plan for the firm load it must serve and by allowing NIPSCO to "right size" its generation resources and avoid the future potential inefficiencies of maintaining excess capacity.

The record demonstrates that if the Rate 831 Settlement, the Revenue Requirement as embodied in the Revenue Settlement, and NIPSCO's proposed cost allocation are approved, there will be no need for a Phase 2 proceeding to establish revised rates. Exhibit D to the Rate 831 Settlement specifically addresses implementation concerns previously raised by some industrial customers.

The Rate 831 Settlement also resolves contested issues regarding the design of Rate 831 that would otherwise require litigation or a true-up process. In particular, each Rate 831 customer has agreed to subscribe to a specific level of firm, Tier 1 demand. Additionally, the parties agreed that the design of Rate 831 should be based on NIPSCO's COSS with costs allocated to Rate 831 based on 194.556 MW of firm demand. These agreements confirm the subscription levels of the Rate 831 customers and establish a cost allocation based on that firm demand, which not only eliminates the need for a true-up process but provides certainty to the Commission and the other parties regarding the share of costs being allocated to Rate 831. The actual Tier 1 subscription is also below that used by NIPSCO in setting cost allocation, but through the Rate 831 Settlement, Rate 831 customers will cover the costs of the 194.556 MW used to allocate costs.

The OUCC and Walmart proposed assessing transition charges on Rate 831 customers. We note that the Commission has no direct statutory authority to prohibit any customer from building or utilizing self-generation nor do we have the ability to preclude a large industrial customer from reducing consumption or moving its operations to another location. In these instances, no transition costs are paid. Rather, as in this case, NIPSCO could file another rate case, seeking to recover the lost revenue from its remaining customers. Moreover, the implementation of transition charges would defeat the purpose of the Rate 831 service structure, which is to maintain load by creating a cost-based rate and providing access to market-priced capacity and energy, not to make NIPSCO's industrial rates less competitive. Based upon the evidence presented, we find that the proposed Rate 831 service structure is reasonable and that no transition charges should be assigned to Rate 831 customers.[43]

In conclusion, the record demonstrates that it was appropriate and reasonably necessary for NIPSCO to revise its industrial rate structure in order to mitigate the credible and preventable threat of large industrial load loss. The record also demonstrates that it is important to NIPSCO and all of its customers to retain the Rate 831 customers and for them to continue contributing to NIPSCO's fixed production costs. We now find that NIPSCO's proposed Rate 831 service structure and the Rate 831 Settlement will best position these large industrial customers to remain cost competitive within their global markets while continuing to contribute to NIPSCO's fixed production costs to serve. This balance enables these customers to be more economically competitive and provides certainty to NIPSCO regarding its obligation to serve. We find that NIPSCO's proposed ARP to implement Rate 831 is in the public interest and will enhance or maintain the value of NIPSCO's retail energy services or property. For the foregoing reasons, the Rate 831 Settlement and Implementation Agreement are approved.

C. Revenue Allocation. We next address the allocation of costs to the various customer classes, as proposed by NIPSCO, and embedded in the terms of the Rate 831 Settlement.

Having considered the evidence presented on the issue of cost allocation, we find the 4CP allocation as proposed by NIPSCO and as reflected in the Corrected Rate 831 Implementation Agreement Exhibit A to the Rate 831 Settlement is reasonable and in the public interest, and is,

[43] While no transition charge is assigned to Rate 831 customers, a risk reduction transition adjustment resulting in a revenue requirement decrease of $3,876,748 is allocated to all non-Rate 831 and Rate 844 customers, as discussed in section 28.D.4.

therefore, approved. The 4CP method for NIPSCO is appropriate for cost allocation based on the fact that in recent years the system peaks in 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. The FERC tests utilized by Dr. Gaske are a commonly used method for analyzing system load characteristics and determining whether a utility has monthly peak periods that can be distinguished from off-peak periods. The 4CP allocation is consistent with the design and operation of NIPSCO's system, and it appropriately and reasonably aligns cost allocation with cost causation.

NIPSCO proposed a mitigation plan to keep Rate 831 at parity and provided for an across-the-board percentage rate increase. NIPSCO began with a fully ACOSS and then developed rates for NIPSCO's Rate 831 customers at parity utilizing the proposed industrial service structure and allocating 184.556 MW of demand at the meter to the industrial class. NIPSCO then allocated the additional revenue requirement over all customer classes equally. NIPSCO proposed the methodology to avoid rate shock to its Residential customers, and this approach aims to mitigate the rate increases so that no class will see an unusually large increase in its base rates while allowing NIPSCO to retain its large industrial customers on the system. Because of residential class subsidies that were retained in prior rate proceedings and the combination of industrial service restructuring and other cost increases, the residential customers would require a rate increase in excess of 30%. Therefore, to mitigate this impact, it was determined that all classes except Rate 831 should receive the same across-the-board percentage rate increase, and the rates for the large industrial class would then be based on the allocated cost of service.

CAC recommended that Rate 831 revenues be maintained at test-year levels under current rates and that the revenues of all other customer classes be increased by an equal percentage. Other than its proposal for a transition charge, the OUCC agreed that it is reasonable to assign the remaining increase across the customer classes on an equal percentage basis. NLMK argued that NIPSCO's proposal reasonably addresses its concerns about industrial bypass and rate mitigation. The Industrial Group agreed with NIPSCO's proposal. Walmart recommended that, if it is not possible to eliminate inter-class subsidies in this case, the Commission should establish a path to eliminate or reduce subsidies in future cases.

With the exception of Walmart, no party opposed NIPSCO's mitigation proposal after the Revenue Settlement was entered. Based upon the evidence of record, we find NIPSCO's request to keep Rate 831 at parity and to provide for an across-the-board percentage rate increase, except for Rate 844 and Rate 850 as discussed below, is supported by substantial evidence, in the public interest, and approved.

Based upon this conclusion, we find that the relevant allocations should be as follows:

Demand Allocation		
Class	Rate Schedule	Allocation
Residential	Rate 811	35.05%
C&GS Heat Pump	Rate 820	0.06%
GS Small	Rate 821	17.50%
Comml SH	Rate 822	0.08%
GS Medium	Rate 823	11.42%

GS Large	Rate 824	14.33%
Metal Melting	Rate 825	0.50%
Off-Peak Serv.	Rate 826	8.34%
Ind. Pwr Serv. – Large – Tier 1	Rate 831	8.32%
Small Industrial Service – LLF	Rate 832	0.88%
Small Industrial Service – HLF	Rate 833	1.99%
Muni. Power	Rate 841	0.24%
Int WW Pumping	Rate 842	0.01%
Railroad	Rate 844	0.15%
Street Lighting	Rate 850	0.54%
Traffic Lighting	Rate 855	0.06%
Dusk-to-Dawn	Rate 860	0.18%
Interdepartmental	Interdepartmental	0.34%
Energy Allocation		
Class	Rate Schedule	Allocation
Residential	Rate 811	28.86%
C&GS Heat Pump	Rate 820	0.09%
GS Small	Rate 821	13.67%
Comml SH	Rate 822	0.10%
GS Medium	Rate 823	10.69%
GS Large	Rate 824	15.54%
Metal Melting	Rate 825	0.78%
Off-Peak Serv.	Rate 826	10.72%
Ind. Pwr Serv. – Large – Tier 1	Rate 831	13.86%
Ind. Pwr Serv. – Large – Tier 2		0.00%
Small Industrial Service – LLF	Rate 832	1.23%
Small Industrial Service – HLF	Rate 833	3.30%
Muni. Power	Rate 841	0.24%
Int WW Pumping	Rate 842	0.00%
Railroad	Rate 844	0.18%
Street Lighting	Rate 850	0.35%
Traffic Lighting	Rate 855	0.05%
Dusk-to-Dawn	Rate 860	0.12%
Interdepartmental	Interdepartmental	0.21%

TDSIC Allocation (based upon firm load)			
Class	Rate Schedule	Transmission Rev. Req. Allocation	Distribution Rev. Req. Allocation
Residential	Rate 811	36.64%	53.48%
C&GS Heat Pump	Rate 820	0.11%	0.19%
GS Small	Rate 821	15.94%	17.65%
Comml SH	Rate 822	0.12%	0.18%
GS Medium	Rate 823	11.67%	9.90%

GS Large	Rate 824	13.82%	10.77%
Metal Melting	Rate 825	0.48%	0.53%
Off-Peak Serv.	Rate 826	8.49%	5.98%
Ind. Pwr Serv. – Large	Rate 831	8.57%	0.00%
Small Industrial Service – LLF	Rate 832	1.05%	0.00%
Small Industrial Service – HLF	Rate 833	2.25%	0.00%
Muni. Power	Rate 841	0.25%	0.33%
Int WW Pumping	Rate 842	0.00%	0.00%
Railroad	Rate 844	0.14%	0.00%
Street Lighting	Rate 850	0.07%	0.27%
Traffic Lighting	Rate 855	0.04%	0.03%
Dusk-to-Dawn	Rate 860	0.04%	0.20%
Interdepartmental	Interdepartmental	0.31%	0.50%

There also was a dispute among the parties regarding the appropriate allocation of demand costs for trackers other than TDSIC. OUCC witness Boerger recommended that "NIPSCO be required to recalculate its Demand Allocation Tracker Allocators to eliminate the Rate 831 Tier 1 Adjustment shown on Page .1 of Rate 831 Implementation Agreement Exhibit and in Attachment 19-E of Mr. Westerhausen's prefiled direct testimony in this case . . . ." Industrial Group witness Phillips and US Steel witness Georgis disagreed with that proposed revision and explained why the tracker allocations proposed by NIPSCO are consistent with system utilization and cost causation. Mr. Phillips stated that it is appropriate to allocate production trackers only to Tier 1 firm load because the Rate 831 customers do not use NIPSCO's production resources for their Tier 2 and 3 loads. At the hearing, Dr. Boerger repeatedly acknowledged during cross-examination that production costs should not be allocated to non-firm load. Tr. at D-94 – D-95, D-96 – D-97. Based upon the evidence of record, the Commission finds that the adjustments proposed in Mr. Westerhausen's prefiled direct testimony contained in Attachment 19-E should be approved.

D. Revenue Settlement. We now review and address the Revenue Settlement, which was opposed by the ICC, ICARE, and LaPorte. We note that the ICC and ICARE do not represent customers in this proceeding, and they explicitly did not oppose the Revenue Settling Parties' agreement to set depreciation accrual rates for the Schahfer and Michigan City coal units based on assumed lives ending in 2032. LaPorte's opposition to the Revenue Settlement highlighted NIPSCO's J.D. Power results and recommended that based on those results, the Revenue Settlement's ROE should be rejected.

(1) Rate Base Update Mechanism Process. For Step 1 Rates, NIPSCO proposed to update its requested relief to be effective subsequent to the receipt of the Commission's final order based upon an actual rate base and capital structure cutoff date of June 30, 2019. As part of its compliance filing, in addition to any other changes identified in this Order, NIPSCO will update its basic rates and charges to reflect the actual rate base and related depreciation and amortization expense, as well as the actual capital structure based on the June 30, 2019 cutoff date. NIPSCO proposed that these rates will become effective with the first billing cycle following the issuance of the Order and remain in effect until replaced by Commission-approved rates resulting from NIPSCO's proposed second compliance filing as part of Step 2.

For Step 2 Rates, the Revenue Settling Parties agreed Step 2 Rates will be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agreed not to include in rate base for Step 2 Rates plant in excess of the amount or value of plant projected in this Cause. The Settling Parties agreed that Step 2 Rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Step 2 Rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019, and calculate the Step 2 Rates using those certified figures. For purposes of this section, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2019. The Revenue Settling Parties and other parties to this proceeding will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Revenue Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 Rates took effect.

We find that the proposed rate base update mechanism process is reasonable, supported by evidence of record, and should be approved.

(2) Revenue Requirement and NOI. The Revenue Settling Parties agree that NIPSCO's base rates will be designed to produce a Revenue Requirement of $1,482,166,740 prior to the application of surviving Riders, which represents a decrease of $63,648,449 from the amount originally requested by NIPSCO. The Revenue Settling Parties also agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as agreed to in the Revenue Settlement, and a $2,000,000 decrease to NIPSCO's proposed O&M Expense. The Revenue Settling Parties agree that NIPSCO's Revenue Requirement results in a proposed authorized NOI of $271,211,585.

As discussed below, we find that the Revenue Settlement provisions regarding NIPSCO's revenue requirement, exclusive of the parties' agreed-upon ROE as discussed below, are reasonable, supported by evidence of record, and are approved. Based on our finding below regarding NIPSCO's authorized ROE, we find and authorize a Revenue Requirement of $1,453,163,108 for Step 1 rates and $1,478,289,992 for Step 2 rates.

(3) NIPSCO's Fair Value Rate Base. The Revenue Settling Parties agreed that the WACC times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based on the Revenue Settlement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding; (2) NIPSCO's proposed capital structure; and (3) an authorized ROE of 9.90%. Neither the components nor value of that fair value rate base is disputed by any party. However, given our finding below regarding NIPSCO's authorized ROE, NIPSCO's overall return for earning test purposes shall be 6.52%. Accordingly, we find that

NIPSCO's fair value rate base for purposes of this proceeding is $4,115,502,071, and that this fair value rate base should be used for purposes of Ind. Code § 8-1-2-6.

(4) NIPSCO's ROE. In its case-in-chief, NIPSCO requested an ROE of 10.80%. OUCC witness Woolridge suggested that NIPSCO's ROE could be set at 8.75%, but in recognition of the practice of gradualism, a 9.25% ROE would be more appropriate. NIPSCO Industrial Group witness Gorman recommended an ROE of 9.35%. Walmart witness Chriss suggested an ROE of 9.69%. The Revenue Settling Parties agreed to an authorized ROE of 9.90%.

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

In response to the Commission's July 16, 2019 docket entry question, LaPorte witness Cearley stated that based on his review of Mr. Rea's testimony and NIPSCO's similar testimony in its last rate case, Mr. Cearley believes that a 25 to 50 basis point downward ROE adjustment is appropriate and reasonable due to NIPSCO's proposals in this case to address its environmental risk elements and its concentration of large industrial load. Mr. Cearley explained that this recommendation is further supported by his recognition in his direct testimony of the compounding effect of NIPSCO's repetitive "...risk adjustments to its return calculations based on environmental risks and its case-after-case request for upward risk adjustments due to a disproportionate level of large industrial load" in each of its last three to four rate case proceedings.

Based upon the totality of evidence presented and the reduced risk to NIPSCO as a result of our approval of the Rate 831 Settlement and Implementation Agreement, we find that the Revenue Settling Parties' agreed-upon ROE of 9.90% should not be approved. Instead, we find that an ROE of 9.75% is within the range of the ROE evidence presented and is approved, as it is reasonable and appropriate in light of the reduced business risk to NIPSCO as a result of approval of the Rate 831 Settlement. In addition, we note that the Rate 831 Settlement and Implementation Agreement explicitly assigns a revenue requirement to the Rate 831 customers. Further, the evidence in this case reflects the transition to the new industrial service has a distinct impact on the non-Rate 831 customers. Accordingly, this 15 basis point reduction and the resulting $3,876,748 revenue requirement decrease shall be applied across the board only to the customer classes experiencing a rate increase as the result of this Order. As such, Rate 831 and Rate 844 customer classes are exempt and are assigned their agreed-to revenue requirements identified in the Rate 831 Settlement. The application of this risk reduction transition adjustment is essentially funded by NIPSCO through a reduction in its ROE and provides a measure of relief to non-Rate 831 customers in light of the reduced risk to NIPSCO and is not inconsistent with the OUCC's transition charge proposal. Furthermore, the approved 9.75% ROE is consistent with Walmart Exhibit No. 2, Exhibit SWC-3 (REVISED) sponsored by Walmart witness Chriss showing that the

average ROE for vertically integrated electric utilities in the country from 2016 through July 10, 2019, is 9.73%.

(5) Depreciation and Amortization Expense. NIPSCO witness Spanos recommended depreciation accrual rates for NIPSCO's electric and common plant assets calculated in accordance with the depreciation study he sponsored. The only witnesses proposing changes to the depreciation accrual rates recommended by Mr. Spanos were OUCC witnesses Garrett and Blakley and Industrial Group witness Gorman, and their issues were resolved pursuant to the Revenue Settlement. No other evidence was presented that disputed the results of Mr. Spanos' depreciation study or the resulting accrual rates. Further, no evidence was presented disputing the Revenue Settlement depreciation accrual rates. We find that the Revenue Settling Parties' agreement regarding depreciation accrual rates should be approved. Those are the original depreciation accrual rates recommended by Mr. Spanos with the following exceptions: (1) the amortization period for retired coal-fired generating units as described in NIPSCO's case-in-chief shall conclude in 2032; and (2) annual depreciation expense shall be adjusted to reflect the removal of $26 million in contingency included in demolition costs. These are the depreciation accrual rates that should be used for purposes of determining NIPSCO's total revenue requirement and that should be used for purposes of depreciation expense that will accrue between the date of this Order and December 31, 2019, for purposes of NIPSCO's Step 2 rate base. Neither ICC nor ICARE took issue with the depreciation study or the depreciation rates that come out of the depreciation study. In fact, ICC witness Medine specifically acknowledged that she takes no issue with the depreciation rate for NIPSCO's steam production plant, which underlies the Revenue Settlement.

In the Revenue Settlement, NIPSCO agreed to implement a credit mechanism upon the retirement of its coal-fired generating units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. This credit mechanism was recommended by OUCC witness Blakley. Mr. Blakey testified that ratepayers should be credited with the effect of the annual depreciation of Schahfer and Michigan City plant. He explained that the credit mechanism would function similarly to a CWIP plant investment tracker, in which plant investment is reduced by associated depreciation over a period and the return "on" is calculated on the new lower net plant balance. While the plant investment is decreasing each year due to depreciation of the investment, NIPSCO would otherwise still receive a return "on" the investment as determined at the time of this rate case. The credit would reflect the difference between the amount authorized in rates and the actual investment amount adjusted for depreciation. The credit would be repeated annually until the physical asset or regulatory asset is fully depreciated or amortized. The credit will be limited to the net plant investment value of the Schahfer and Michigan City coal-fired generating units embedded in the base rates established in this Cause and the associated accumulated depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in the Revenue Settlement Paragraph B.1(a); and (2) the NOI established in the Revenue Settlement Paragraph B.1(b) for purposes of its earnings test. NIPSCO agreed to hold annual meetings preceding the 30-day compliance filing with interested stakeholders. No party opposed the credit mechanism, and we find it is reasonable and should be approved.

ICC and ICARE were the only parties to oppose the provisions of the Revenue Settlement related to depreciation. Ms. Medine specifically stated that she takes no issue with the depreciation rate for NIPSCO's steam production plant underlying the Revenue Settlement. However, both witnesses Medine and Griffey testified that approval of NIPSCO's regulatory asset treatment

resulting from the Revenue Settlement is unnecessary at this time and should be deferred until the coal plants are actually retired. Mr. Griffey recommended that the Commission reject any aspect of the Revenue Settlement that forecloses flexibility and decline to approve explicitly or implicitly NIPSCO's retirement dates.

As noted by Ms. Shikany during cross-examination, approval of the Revenue Settlement – and the attendant depreciation/amortization of amounts based upon a 2032 date – results in zero difference in the revenue requirement agreed upon. Tr. at B-28. In fact, NIPSCO's agreement in the Revenue Settlement to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City generating units reflected in NIPSCO's rate base at the time a final order is issued and the actual investment amount adjusted for depreciation as outlined in OUCC witness Blakely's direct testimony results in customer savings. Based upon all the evidence, the Commission finds that the depreciation rates agreed upon in the Revenue Settlement are reasonable and should be approved. However, in approving the agreed-upon depreciation rates, we do not, either explicitly or implicitly, approve NIPSCO's retirement dates.

During the hearing held in this Cause, NIPSCO witness Shikany explained the need for a determination regarding the treatment of the remaining book value of the Schahfer and Michigan City generating units at the time of their retirement. She explained that the Uniform System of Accounts is very prescriptive of how to treat a normal retirement. Tr. at B-33. She explained that under normal retirement accounting due to the use of composite depreciation, Mr. Spanos could assign sufficient accumulated depreciation to the Bailly assets to reflect a full recovery by reducing the accumulated depreciation. Tr. at B-33. However, she explained that once the Schahfer units are retired, there will not be enough time to collect the remaining book value through depreciation. Therefore, NIPSCO has proposed to treat the retirement as extraordinary, which needs the Commission's approval. Tr. at B-34. Based upon Ms. Shikany's explanation in Revenue Settlement rebuttal testimony and in redirect examination why a determination is needed at this point concerning the regulatory asset and the fact that customers are not adversely affected by such confirmation (as is further confirmed by the fact that no customer parties opposed this aspect of the Revenue Settlement) and that NIPSCO would face financial risk were we not to provide such confirmation, we therefore find that granting authority for the regulatory asset treatment contained in the Revenue Settlement is reasonable and in the public interest. Accordingly, we find that should the Schahfer and/or Michigan City generating units be retired before the end of 2032, the retirement(s) should be deemed extraordinary pursuant to the FERC Uniform System of Accounts. Further, we find that the net book value of the retiring unit(s) at retirement should be recorded as a regulatory asset when the units are actually retired; that the regulatory asset should be amortized over a period expiring at the end of 2032; that the annual amortization expense should be recovered through rates; and that the regulatory asset should be reflected in NIPSCO's net original cost rate base upon which a full return should be authorized for ratemaking purposes.

With respect to the remaining issue related to amortization expense, the evidentiary record includes proposals from NIPSCO and the OUCC proposing competing approaches to the amortization and amount of the regulatory assets for rate case expense, and for the amortization of the TDSIC deferred balance. The Revenue Settling Parties agreed to resolution of these issues providing that NIPSCO's annual amortization expense shall be the amount calculated by NIPSCO in this proceeding, with the exception that the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC Seven-Year Plan, FMCA,

MATS, EDR, and Electric Rate Case Expense of seven years, and that if it has not been already addressed by an intervening base rate case order, after the completion of the seven-year period, NIPSCO will make a tariff filing to reflect the reduction in amortization expense. We find this resolution to be reasonable and appropriate.

(6) Other Specific Ratemaking Issues. As discussed above, the Revenue Settling Parties agreed to a level of operating expenses to be incorporated in NIPSCO's revenue requirement, which includes the following issues:

a. TCJA. In its June 1, 1987 Interim Order issued in Cause No. 38194 adopting the recommendations of the Report of the Executive Committee on April 15, 1987, the Commission concluded that all excess deferred taxes should be passed back using the ARAM. After the adoption of the TCJA, the Commission opened an investigation in Cause No. 45032 into the impacts of that TCJA and possible rate implications. The first phase was to address immediate rate reductions to remove the difference between: (1) the amount of federal taxes that the given Rate or Charge was designed to recover based on the tax rate in effect at the time the Rate or Charge was approved; and (2) the amount of federal taxes that would have been embedded in the given Rate or Charge had the new tax rate applicable to NIPSCO as a result of the TCJA been in effect at the time of approval. The second phase was to address all remaining issues, including: (1) the amount and amortization of normalized and non-normalized excess ADIT and the regulatory accounting being used for estimated impacts resulting from the TCJA; and (2) the timing and method for how these benefits will be realized by customers, whether directly or indirectly.

In its sub-docket resulting from Cause No. 45032 (Cause No. 45032-S5), NIPSCO did not file a case-in-chief and instead filed an Unopposed Motion to Hold in Abeyance the Procedural Schedule, which was granted by the Commission on August 15, 2018. In its motion, NIPSCO proposed a method by which it would return excess income tax revenue recovered through rates between January 1, 2018 and April 30, 2018, which was at that time reflected as a regulatory liability and stated that the parties will resolve all other Phase 2 issues in a rate case to be filed by December 31, 2018.

In the Revenue Settlement, the Revenue Settling Parties agreed that: (1) NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in NIPSCO's revenue requirement at the ARAM, estimated at the time of the Revenue Settlement to be 26 years; and (2) with regard to NIPSCO's Unprotected and Other Excess ADIT balance, which totaled approximately $137,789,071 as of December 31, 2017, NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Step 2 Rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030, and if not already addressed by an intervening base rate case order, after the completion of the ten-year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization. The total amount of unprotected excess ADIT to be passed back to customers will be addressed in NIPSCO's next general rate case.

The resolution proposed for issues associated with the return of excess ADIT balances is supported by the uncontested evidence of record. The utilization of ARAM as the basis for the pass back of ADIT associated with protected assets is consistent with regulations promulgated by the U.S. Department of Treasury. The amortization of unprotected and other excess ADIT is

subject to Commission discretion. We note that the amortization of excess ADIT as agreed to in the Revenue Settlement was uncontested by the non-settling parties. We find the proposed treatment of ADIT balances as proposed by the Revenue Settling Parties to be reasonable and in the public interest. This resolves all remaining issues in Cause No. 45032-S5.

b. Rate Design. In its case-in-chief, NIPSCO proposed an increase in the Residential Customer Charge from $14.00 to $17.00 per month. CAC proposed a reduction to $12.55. Sierra Club proposed a reduction to $12.77. The OUCC proposed no change to the Residential Customer charge. We find that the Revenue Settling Parties' agreement that rates should be designed with the Residential Customer Charge set at $13.50 per month is reasonable and should be approved.

In its case-in-chief, NIPSCO proposed to replace Rates 732 and 733 with Rate 830. The Industrial Group proposed low load factor and high load factor rates for Rate 830. We find that the Revenue Settling Parties' agreement that Rate 830 be split into Rates 832 and 833 to reflect the current structure of Rates 732 and 733 (as proposed in Industrial Group witness Phillips' direct testimony and NIPSCO witness Westerhausen's rebuttal testimony) and that those rates provide for back-up and maintenance provisions reflected in current Rider 776, is reasonable and should be approved.

The Revenue Settling Parties agreed that Rate 844 shall see no increase resulting from this proceeding given its importance to northwest Indiana in providing public transportation between South Bend and Chicago. We find this provision is reasonable and should be approved.

c. Tariff Changes – Trackers and Riders. The Revenue Settling Parties agreed: (1) NIPSCO shall flow through the RTO Tracker 100% of all margins, including any net losses, from OSS, down to zero; (2) NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years; and (3) NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief. We find this provision is reasonable and should be approved.

d. Low-Income Program Commitment. The Revenue Settlement includes a provision that NIPSCO commits to seek approval of a voluntary low-income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process that NIPSCO has already established with interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, will not impact NIPSCO's revenue requirement and will be discussed in the collaborative process. We find this provision is reasonable and should be approved.

e. Rate 850 – Street Lighting. The Revenue Settlement includes a provision that the lamp charge for TDSIC LED NIPSCO-owned streetlights retrofitted before approval of the final order in this Cause will not increase. Pursuant to Joint Exhibit 8, the resulting revenue deficiency will be allocated to other customer and NIPSCO-owned lamp types

in Rate 850. We note no evidence was presented in opposition to this provision. We find this provision as modified by Joint Exhibit 8 to be reasonable and should be approved.

(7) Operating Income under Present Rates. For the 12 months ending December 31, 2019, NIPSCO's projected jurisdictional operating income from its electric utility operations at current rates was shown by NIPSCO to be as follows:

Total Operating Revenue		$1,527,202,346
Less Total Fuel Costs	$407,025,357	
Gross Margin		$1,120,176,989
Less Total Operations and Maintenance Expense	$495,797,094	
Less Total Depreciation Expense	$269,915,038	
Less Total Amortization Expense	$43,180,556	
Less Total Taxes Other Than Income	$39,273,167	
Less Federal and State Taxes	$35,787,103	
Total Operating Expenses including Income Taxes		$883,952,958
Net Operating Income		$236,224,031

Petitioner's Attachment 4-A-S2-S.[44] The evidence of record supports the conclusion that NIPSCO's current rates and charges are unjust, unreasonable, and inconsistent with the public interest and that NIPSCO should be authorized to adjust its rates so as to permit the provision of reasonably adequate service and facilities at just and reasonable rates.

(8) Rate Level to be Authorized. Based on the Revenue Settlement and the Commission's risk reduction transition adjustment, NIPSCO should be authorized a fair rate of return of no more than $268,330,735 yielding an overall return of 6.52%, based upon: (1) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding; (2) NIPSCO's proposed capital structure adjusted for the Commission's risk reduction transition adjustment, which prescribes an authorized ROE of 9.75%.

Based on the foregoing, the Commission finds that NIPSCO should be authorized rates projected to produce operating revenue for Step 1 and Step 2, as follows:

	Step 1	Step 2
Operating Revenues	$1,453,163,108	$1,478,289,992
Operating Expenses and Taxes		
Fuel Costs	$321,765,239	$321,765,239
Operating & Maintenance Expenses	$489,075,656	489,128,103
Depreciation Expense	$261,122,046	$269,915,038

[44] The values shown were provided in support of Petitioner's projected Step 2 rates to be based on plant in service and capital structure as of December 31, 2019, and thereby correspond to the close of Petitioner's 2019 Forward Test Year.

Amortization Expense	$39,292,177	$43,180,556
Taxes Other Than Income Taxes	$39,184,168	$39,214,372
Income Taxes	$46,342,112	$46,755,949
Total Operating Expenses and Taxes	$1,196,781,399	$1,209,959,257
Projected Net Operating Income	$256,381,710	$268,330,735

(9) Conclusion Regarding Revenue Settlement. Based upon the evidence of record, we find and conclude that the Revenue Settlement presents a balanced and comprehensive resolution of the revenue and other miscellaneous issues set out above. Therefore, the Commission approves the Revenue Settlement's terms and conditions, exclusive of the agreed-upon ROE, as reasonable, supported by substantial evidence, and in the public interest.

(10) Effect of Settlement. With regard to future citation of this Order, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC 3/19/1997).

E. Electric Service Tariff and Standard Contract. NIPSCO witness Westerhausen sponsored NIPSCO's Proposed Tariff,[45] Agreement for Electric Service for Rates 824, 825, 832, 833, and 844,[46] and Agreement for Electric Service for Rate 831 and Rider 876.[47] The facts that affect the specific schedule charge amounts have been discussed throughout this Order and shall be incorporated in the compliance filing to this Order. With the exception of: (1) NIPSCO's proposed changes to reflect its proposed industrial service structure; (2) NIPSCO's proposed updates to its FAC Tracker; and (3) NIPSCO's proposal to discontinue its ECR Mechanism, no party objected to NIPSCO's Proposed Tariff and Standard Contract for Electric Service. Based upon the evidence of record, the uncontested proposals for NIPSCO's Proposed Tariff and Standard Contract for Electric Service, are approved as proposed by NIPSCO.

Based upon the evidence of record and consistent with our approval of the Rate 831 Settlement, NIPSCO's proposed Rates 831, 832, and 833, and Riders 881 and 882 reflecting its industrial service structure are approved.

Mr. Westerhausen explained that the FAC Tracker had been revised: (1) to update the average cost of fuel in base rates in this proceeding; (2) 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 the FAC Tracker; and (3) to separately state the URT on customer bills instead of including it in the calculation of the factors in this Rider. The OUCC recommended that the Commission continue allowing the OUCC and intervenors to file their testimony and report 35 days after NIPSCO files its FAC application and testimony. No party opposed that

[45] Attachment 19-A, as corrected (January 2, 2019, January 22, 2019, and June 7, 2019) and revised in Attachment 19-R-A (Rate 832), Attachment 19-R-B (Rate 833), Attachment 19-R-E (Appendix A), Attachment 19-R-H (Rate 831), and Attachment 19-S2-A (Rate 831 and Riders 881 and 882).
[46] Attachment 19-R-M.
[47] Attachment 19-R-O.

recommendation and the Commission agrees to keep it in place. For purpose of NIPSCO's FAC proceedings, we find NIPSCO's base cost of fuel to be $0.026736.

With regard to NIPSCO's proposal to discontinue its ECR Mechanism, NIPSCO witness Westerhausen 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. ICC witness Medine recommended that approval to discontinue the ECR Mechanism should only be provided if NIPSCO agrees to exclude all variable costs currently in the ECR Mechanism and in base rates from the calculation of its offer prices when bidding its units into the market. NIPSCO witness Campbell testified that NIPSCO did not include inappropriate components of its offers to MISO, nor were they imprudent with respect to its generation decision-making. He explained that the variable costs of production that are built into the agreed revenue requirement are based upon production cost modeling, which is based upon NIPSCO's variable costs of production in relation to other sources of power that are offered into the MISO market. This precise issue was raised and rejected in our April 29, 2019 Order in Cause No. 38706 FAC 122 ("FAC 122 Order"). In our FAC 122 Order, we found that NIPSCO demonstrated that its current offer strategy of its generation units into the MISO energy market was reasonable. In that order, we also found that "NIPSCO has adequately demonstrated that it 'has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]' Ind. Code § 8-1-2-42." The Commission reaches the same conclusion in this case. Based upon the evidence of record and consistent with our approval of the Revenue Settlement, NIPSCO's proposal to discontinue its ECR Mechanism is approved.

F. Accounting Relief. Besides the accounting relief requested and which we have already approved regarding the depreciation rates and estimated useful lives of generating assets, NIPSCO seeks accounting authority to defer, as a regulatory asset, discounts offered to certain customers under its EDR for recovery in a future rate case; authority to defer, as a regulatory liability, an amount equal to 100% of: (1) annual 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. No party objected to NIPSCO's requested accounting authority. Based upon the evidence of record, and consistent with our approval of the Revenue Settlement, we find that NIPSCO's request is reasonable and should be approved.

G. DSM. 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 EE 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. No party objected to NIPSCO's request. Based upon the evidence of record, we find that NIPSCO's request is reasonable and should be approved.

H. RTO Tracker and OSS Margin Sharing. NIPSCO proposed to update Rider 771 – Adjustment of Charges for Regional Transmission Organization to: (1) remove MISO charges and credits and collect 100% of MISO charges that are not included in the FAC through the RTO; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any margins net of expenses through the RTO; (3) remove all back-up and

maintenance margins currently included in base rates and pass back 100% of such margins net of expenses through the RTO Tracker; and (4) change the allocation methodology. No party objected to NIPSCO's request, except to the extent they objected to the allocation methodology proposed for Rate 831. Based upon the evidence of record and our approval of the Rate 831 Settlement, we find that NIPSCO's request is reasonable and should be approved.

I. Regulatory Assets. NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with Commission orders. Ms. Shikany described these costs as follows: TDSIC Remand Amount in accordance with the September 23, 2015 Order on Remand in Consolidated Cause Nos. 44370/44371; TDSIC Costs in accordance with the July 12, 2016 Order in Cause No. 44733; Federally Mandated Costs in accordance with the January 29, 2014 order in Cause No. 44340, December 13, 2017 Order in Cause No. 44872, and July 12, 2017 Order in Cause No. 44889; and MATS Expenses in accordance with the October 10, 2013 Order in Cause No. 44311. Based on the evidence of record, and consistent with our approval of the Revenue Settlement, we find that NIPSCO's request is reasonable and should be approved.

29. Confidential Information. NIPSCO filed motions for protective order on October 31, 2018, February 27, 2019, March 13, 2019, and July 17, 2019, all of which were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued docket entries finding all of the information described in the motions to be preliminarily confidential, after which such information was submitted under seal. We find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. The Stipulation and Settlement Agreement on Rate 831 Implementation between NIPSCO, Industrial Group, NLMK Indiana, and US Steel attached hereto is approved and adopted by the Commission, in its entirety, without change or modification.

2. The Stipulation and Settlement Agreement on Less than all the Issues between NIPSCO, Industrial Group, NLMK Indiana, US Steel, CAC, Walmart, NICTD, Sierra Club, IMUG, and the OUCC attached hereto is approved and adopted by the Commission, exclusive of the Revenue Settling Parties' agreed-upon ROE, as set forth in Finding 28.C.(4) above, which impacts the Revenue Settling Parties' agreed-upon Revenue Requirement.

3. NIPSCO is authorized to implement the authorized rate increase in two steps to be implemented as set forth in Ordering Paragraphs 4 and 5 below. Prior to implementing the rates authorized in this Order, NIPSCO shall file the tariff and applicable rate schedules under this Cause with the Commission, and such rates shall be effective subject to the Energy Division's review and agreement with the amount reflected.

4. For Step 1, NIPSCO shall file new schedules of rates and charges with the Energy

Division of the Commission based on the agreed revenue requirement as adjusted to reflect the order-approved ROE, original cost of NIPSCO's net utility plant in service, actual capital structure, and associated depreciation and amortization expense as of June 30, 2019, maintaining the amortization of the protected excess ADIT using ARAM and unprotected property using ARAM and other unprotected excess ADIT using ten years. Step 1 rates will become effective on the next billing cycle following NIPSCO's submission of its Step 1 compliance filing.

5. For Step 2, NIPSCO shall file new schedules of rates and charges with the Energy Division of the Commission based on the agreed revenue requirement, as adjusted to reflect the order-approved ROE, as of December 31, 2019, as adjusted, if necessary, to reflect the lesser of: (1) NIPSCO's forecasted test-year-end rate base as updated in NIPSCO's rebuttal evidence ($4,115,502,071); or (2) NIPSCO's certified test-year-end net plant in service as of December 31, 2019. Step 2 rates shall include the amortization of $12,170,384 per year in the revenue requirement related to the pass back of the unprotected property and other unprotected excess ADIT to customers. Step 2 rates will be certified and go into effect, subject to refund, on March 1, 2020. The OUCC and intervening parties will have 60 days from the date of certification to state any objections to NIPSCO's certified test-year-end net plant in service. If there are objections, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued-up (with carrying charges) retroactive to the date that NIPSCO's Step 2 rates became effective.

6. All schedules of rates and charges submitted under Ordering Paragraphs 4 and 5 shall be developed according to the agreed on rate design as described by the terms of the Revenue Settlement and the allocation among customer classes as described by the terms of the Rate 831 Settlement, as set forth in Finding 28.C. above.

7. The proposed IURC Electric Service Tariff, Original Volume No. 14 is approved consistent with the Rate 831 Settlement and Revenue Settlement and this Order, inclusive of the associated General Rules and Regulations and Standard Contracts.

8. NIPSCO's proposed depreciation rates are approved consistent with the Revenue Settlement and this Order.

9. NIPSCO is authorized to create a regulatory asset equal to the remaining net book value of its R.M. Schahfer Generating Units and Michigan City Generating Unit at the date of each unit's retirement to be amortized through December 31, 2032 consistent with the Revenue Settlement and this Order.

10. NIPSCO is authorized: (1) to defer as a regulatory asset, discounts offered to certain customers under its Economic Development Rider for recovery in a future rate case; and (2) to defer as a regulatory liability, an amount equal to 100% of annual off-system sales margins net of expenses and back-up and maintenance demand margins, both for pass back through the RTO Tracker.

11. The information submitted under seal in this Cause pursuant to motions for protective orders is determined to be confidential and exempt from public access and disclosure

pursuant to Ind. Code § 24-2-3-2 and § 5-14-3-4.

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

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

APPROVED: DEC 4 2019

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

Mary M. Becerra
Secretary of the Commission

FILED
April 26, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 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

SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT ON LESS THAN ALL THE ISSUES

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, on behalf of itself and NIPSCO Industrial Group; NLMK Indiana; United States Steel Corporation; the Citizens Action Coalition of Indiana, Inc.; Walmart Inc.; Northern Indiana Commuter Transportation District; Sierra Club; and the Indiana Office of Utility Consumer Counselor (collectively the "Settling Parties"),

respectfully submits the attached Stipulation and Settlement Agreement on Less Than all the Issues (the "Settlement Agreement").

The Settlement Agreement resolves the revenue requirements issues and other miscellaneous issues. The Settling Parties are continuing to work to see if any other parties will join the Settlement Agreement. The Settling Parties are also continuing discussions regarding revenue allocation and Rate 831 rate design to attempt to reach resolution. The Settling Parties will provide the Commission with a status report on or before April 30, 2019 regarding the status of settlement negotiations on revenue allocation and Rate 831 rate design and to advise if any additional parties have agreed to join the Settlement Agreement.

Respectfully submitted on behalf of the Settling Parties,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic transmission this 26th day of April, 2019 to:

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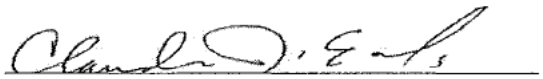
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Claudia J. Earls

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 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**

STIPULATION AND SETTLEMENT AGREEMENT ON LESS THAN ALL THE ISSUES

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 25th day of April, 2019, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); the NIPSCO Industrial Group ("Industrial Group");[1] NLMK Indiana; United States Steel Corporation; the Citizens Action Coalition of Indiana, Inc.; Walmart Inc.; Northern Indiana Commuter Transportation District; Sierra Club; and the Indiana Office of Utility Consumer Counselor (the "OUCC") (collectively the "Settling Parties"), who stipulate and agree for purposes of settling the revenue requirements issues in this Cause that the terms and conditions set forth below represent a fair and reasonable resolution of the revenue requirement issues and other miscellaneous issues subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission

[1] The Industrial Group is comprised of Accurate Castings, Inc., ArcelorMittal USA, BP Products North America, Inc., Cargill, Inc., Enbridge Energy, Praxair, Inc., and USG Corporation.

("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein.

A. Background

1. NIPSCO's Current Rates and Charges: 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"). The basic rates and charges approved in the 44688 Rate Case Order went into effect on September 29, 2016. Those rates and charges remain in effect today, as modified by various riders approved by the Commission from time to time; and as modified on May 1, 2018 pursuant to the Commission's January 3, 2018 Order in Cause No. 45032 to reflect the reduction in the federal income tax rate from 35 percent to 21 percent in accordance with the Tax Cut and Jobs Act of 2017 ("TCJA").[2]

2. NIPSCO's Current Depreciation and Accrual Rates: NIPSCO's current common and electric depreciation rates were approved in the Commission's 44688 Rate Case Order. The Commission's Orders in Cause Nos. 44012 and 44340 approved specific depreciation accrual rates to be applied to plant and equipment identified in those proceedings. For other items of property, NIPSCO's current depreciation accrual rates were approved in the 44688 Rate Case Order.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings: NIPSCO files a quarterly FAC proceeding in accordance with Indiana Code §8-1-2-42(d) in Cause No. 38706-FAC-XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs. In accordance with Rider 770 – Adjustment of Charges for Cost of Fuel

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

Rider, 25% of costs associated with credits paid for interruptible and/or curtailable load under Rider 775 – Interruptible Industrial Service Rider are also recovered in quarterly FAC proceedings. Historically, NIPSCO has agreed that the OUCC and other interested parties should have thirty-five (35) days to review NIPSCO's FAC filings and NIPSCO has agreed to continue that practice.

4. NIPSCO's Tracking Mechanisms: In coordination with its FAC proceedings, NIPSCO files semi-annual proceedings in: (a) Cause No. 44156-RTO-XX to recover costs associated with MISO non-fuel costs and revenues and to provide for off-system sales sharing through its Rider 771 – Adjustment of Charges for Regional Transmission Organization ("RTO Tracker") and Appendix C – Regional Transmission Organization Adjustment Factor approved by the Commission in its 44688 Rate Case Order; and (b) Cause No. 44155-RA-XX to recover prudently incurred capacity costs through its Rider 774 – Adjustment of Charges for Resource Adequacy ("RA Tracker") and Appendix F – Resource Adequacy Adjustment Factor approved by the Commission in its 44688 Rate Case Order.[3] In addition, pursuant to Rider 774, 75% of costs associated with credits paid for interruptible load under Rider 775 are recovered through the RA Tracker.

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

In its August 25, 2010 Order in Cause No. 43526, the Commission found that NIPSCO's prudently incurred capacity should be recovered through the Resource Adequacy or RA Adjustment. In its December 21, 2011 Order in Cause No. 43969, the Commission approved the implementation of the RA Adjustment approved in Cause No. 43526 by approving Rider 674 and Appendix F.

NIPSCO files semi-annual proceedings in Cause No. 42150-ECR-XX to recover costs associated with qualified pollution control property, clean coal technology and clean energy projects to allow NIPSCO to comply with various environmental obligations through its Rider 772 – Adjustment of Charges for Environmental Cost Recovery Mechanism ("ECRM Tracker") and Appendix D — Environmental Cost Recovery Mechanism Factor approved by the Commission in its 44688 Rate Case Order.[4]

NIPSCO files an annual proceeding in Cause No. 43618-DSM-XX to recover program costs and lost revenues associated with approved demand side management and energy efficiency programs through its Rider 783 – Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA) and Appendix G – Demand Side Management Adjustment Mechanism (DSMA) Factor initially approved by the Commission in its May 25, 2011 Order in Cause No. 43618. In its February 27, 2017 Order in Cause No. 43618-DSM-11, the Commission approved a modification to NIPSCO's Rider 783 to move from a semi-annual to annual filing.

NIPSCO files an annual proceeding in Cause No. 44198-GPR-XX to revise the Green Power Rider rate set forth in its Rider 786 – Green Power Rider and Appendix H – Green Power Rider Rate. The initial tracking mechanism was approved in the Commission's December 19, 2012 Order in Cause No. 44198. In its December 28, 2016 Order in Cause No. 44198-GPR-8 the Commission approved a modification to NIPSCO's Rider 786 to move from a semi-annual to annual filing.

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[4] The Commission approved two tracking mechanisms in its November 26, 2002 Order in Cause No. 42150 by approving Rider 672 – Adjustment of Charges for Environmental Cost Recovery Mechanism and Appendix D – Environmental Cost Recovery Mechanism Factor and Rider 673 □ Adjustment of Charges for Environmental Expense Recovery Mechanism and Appendix E – Environmental Expense Recovery Mechanism Factor. The Commission subsequently approved the consolidation of Riders 672 and 673 in its 44688 Rate Case Order.

NIPSCO files a semi-annual proceeding in Cause No. 44340-FMCA-XX to recover federally mandated costs through its Rider 787 – Adjustment of Charges for Federally Mandated Costs ("FCMA") and Appendix I – Federally Mandated Cost Adjustment Factor. The initial tracking mechanism was approved in the Commission's January 29, 2014 Order in Cause No. 44340.

NIPSCO files a semi-annual proceeding in Cause No. 44733-TDSIC-XX to recover 80% of eligible and approved capital expenditures and transmission, distribution, and storage system improvement charge costs for eligible projects through Rider 788 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix J – Transmission, Distribution and Storage System Improvement Charge. The initial tracking mechanism was approved in the Commission's February 17, 2014 Order in Cause No. 44371.

5. This Proceeding: On October 31, 2018, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to increase its retail rates and charges for electric utility service through the phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders; (3) approving revised common and electric depreciation rates applicable to electric plant in service; (4) approving necessary and appropriate accounting relief; (5) approving a new service structure for industrial rates ("Rate 831"); (6) authorizing NIPSCO to implement temporary rates; and (7) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on October 31, 2018. On February 13, 2019, the OUCC and intervenors filed their

respective cases-in-chief and on March 15, 2019, NIPSCO filed its rebuttal testimony and exhibits and several intervenors filed cross-answering testimony and exhibits.

As discussed within NIPSCO's Verified Petition, and the testimony of various parties including NIPSCO, this rate case filing was driven by several developments subsequent to the 44688 Rate Case Order. First, NIPSCO needed to address unresolved impacts related to the TCJA, particularly the return of excess Accumulated Deferred Income Tax ("ADIT"). Second, NIPSCO sought to modify its depreciation rates and cost recovery in rates for NIPSCO's coal-fired generating assets to reflect the useful life of those assets as reflected in NIPSCO's Integrated Resource Plan. Third, as part of an alternative regulatory plan under Ind. Code §8-1-2.5-6, NIPSCO proposed to modify its industrial service rate structure to respond to a changing energy landscape and economic conditions that directly impact its largest customers.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income:

(a) Revenue Requirement: The Settling Parties agree that NIPSCO's base rates will be designed to produce $1,482,166,740 prior to application of surviving Riders. This Revenue Requirement is a decrease of approximately $63.648 Million from the amount originally requested by NIPSCO. The Settling Parties agree the Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below, and a $2,000,000 decrease to NIPSCO's proposed O&M Expense.

(b) Net Operating Income: The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.1(a) above results in a proposed authorized net operating income ("NOI") of $271,211,585.

2. Fair Value Rate Base, Capital Structure, and Fair Return:

(a) Fair Value Rate Base: The Settling Parties agree that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based on this Agreement, the Settling Parties agree that NIPSCO should be authorized a fair rate of return of 6.59%, yielding an overall return for earnings test purposes of $271,211,585, based upon:

(i) an original cost rate base of $4,115,502,071, inclusive of materials, supplies, production fuel, and regulatory assets, as proposed by NIPSCO in its case-in-chief unless otherwise corrected during the course of the proceeding;

(ii) NIPSCO's proposed capital structure; and

(iii) an authorized return on equity ("ROE") of 9.90%.

(b) Capital Structure and Fair Return: Based on the following capital structure, the 9.90% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	Dollars	Cost %	WACC %
Common Equity	$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%
Post-Retirement Liability	$66,142,914	0.00%	0.00%
Prepaid Pension Asset	$(435,272,223)	0.00%	0.00%
Post-1970 ITC	$2,014,831	8.30%	0.00%
Totals	**$5,987,004,559**		**6.59%**

3. Depreciation and Amortization Expense:

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

(i) the amortization period for retired coal-fired generating units as described in NIPSCO's case-in-chief shall conclude in 2032, which presumes the retirement of the R.M. Schahfer ("Schahfer") Generating Units in 2023 and the Michigan City Generating Unit in 2028; and

(ii) annual depreciation expense shall be adjusted to reflect the removal of $26 Million in contingency expense included in demolition costs, as proposed by Industrial Group Witness Gorman.

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

(i) the amount of annual amortization expense shall be modified to reflect an amortization rate of the TDSIC Remand, TDSIC 7 Year Plan, FMCA, MATs, EDR and Electric Rate Case Expense of seven (7) years.

If not already addressed by an intervening base rate case order, after the completion of the seven (7) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(c) Revenue Credit: NIPSCO agrees to implement an annual credit mechanism to reflect the difference between the value of the Schahfer and Michigan City Generating Units reflected in NIPSCO's rate base at the time a Final Order is issued in this proceeding and the actual investment amount adjusted for depreciation as outlined in OUCC Witness Blakely's direct testimony. NIPSCO agrees to implement the credit upon the retirement of the Generating Units, which is planned to be no later than 2023 for Schahfer and 2028 for Michigan City. The credit will be limited to the net plant investment value of the Schahfer and Michigan City Generating Units embedded in the base rates established in this Cause and the associated accumulated

depreciation upon retirement of the units. NIPSCO will utilize a standardized form and will adjust: (1) revenue requirement established in paragraph B.1(a), and (2) the NOI established in paragraph B.1(b) for purposes of its earnings test. NIPSCO agrees to hold annual pre-filing meetings preceding the 30 day compliance filing with interested stakeholders.

4. Tax Cut and Jobs Act:

(a) Protected and Net Operating Loss Excess ADIT: The Settling Parties agree that NIPSCO's Protected and Net Operating Loss Excess ADIT, totaling approximately $(203,164,460) shall be passed back in NIPSCO's revenue requirement at the average rate assumption method ("ARAM"), estimated at the time of this Agreement to be 26 years.

5. Unprotected and Other Excess ADIT: The Settling Parties agree that NIPSCO's Unprotected and Other Excess ADIT balance, totaled approximately $137,789,071 as of December 31, 2017. NIPSCO shall amortize $12,170,384 per year in the revenue requirement with the implementation of Phase II rates on March 1, 2020. At the time of the next rate case, the remaining balance shall be included in the revenue requirement and fully amortized by December 31, 2030. If not already addressed by an intervening base rate case order, after the completion of the ten (10) year period, NIPSCO agrees to make a tariff filing that will reflect the ending of the amortization.

6. Phase II Rate Implementation:

(a) Phase II Rates Subject to Refund: Phase II rates shall be based on forecasted net plant certified to have been completed and placed in service no later than December 31, 2019. NIPSCO agrees it shall not be permitted to include in rate base for Phase II rates plant in excess of the amount or value of plant projected in this Cause. The Settling Parties agree that Phase II rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2019. Prior to implementation of Phase II rates, NIPSCO will certify the net plant in service and current capital structure as of December 31, 2019 and calculate the Phase II rates using those certified figures. For purposes of this Agreement, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies and that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2019. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a

hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Phase II rates were put into place.

7. Revenue Allocation:

(a) The Settling Parties agree to continue discussions regarding revenue allocation and Rate 831 rate design to attempt to reach resolution and also agree to provide the Commission with a status report on or before April 30, 2019 regarding the status of settlement negotiations on revenue allocation and Rate 831 rate design.

8. Rate Design:

(a) The Settling Parties have agreed on the following issues related to rate design.

(i) Residential Customer Charge: The Settling Parties agree that rates should be designed with the Residential Customer Charge set at $13.50/month.

(ii) Rate 830: The Settling Parties agree that as proposed in Industrial Group Witness Phillips' Direct Testimony and NIPSCO Witness Westerhausen's Rebuttal Testimony, Rate 830 shall be split into Rates 832 and 833 which shall reflect the current structure of Rates 732 and 733, and

provide for backup and maintenance provisions reflected in current Rider 776.

(iii) Rate 844: The Settling Parties agree that Rate 844 shall see no increase in its base rates resulting from this proceeding given its importance to Northwest Indiana in providing public transportation between South Bend and Chicago.

9. Tariff Changes:

(a) Trackers and Riders:

(i) NIPSCO agrees to flow through the RTO Tracker 100% of all margins, including any net losses, from off-system sales, down to zero.

(ii) NIPSCO shall discontinue the ECRM Tracker and shall recover the remaining regulatory asset over two years.

(iii) The Settling Parties agree that NIPSCO's proposal for treatment of economic development rider contracts to Rider 877 shall be approved, including the deferral mechanism as described in NIPSCO's case-in-chief.

10. Low Income Program Commitment:

(a) NIPSCO commits to seek approval of a voluntary low income program within six months of a final order in this proceeding. Other program details will be established in good faith through the collaborative process NIPSCO has already established with

NIPSCO and interested stakeholders. NIPSCO will file with the Commission a report on the program which includes number of participants, number of applicants denied, amounts awarded to participants, total amount of funds distributed, and other information to be determined by the collaborative process. Funding for the program, which will be voluntary for all customers, and which will not impact NIPSCO's revenue requirement, will be discussed in the collaborative process.

C. Procedural Aspects and Presentation of the Agreement

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

2. The Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding, and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

3. If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or cited by any party in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of material condition deemed unacceptable to any Settling Party. If the Commission does not approve

the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications. In the event the Agreement is withdrawn, the Settling Parties will request an Attorney's Conference to be convened to establish a procedural schedule for the continued litigation of this proceeding.

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

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

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

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

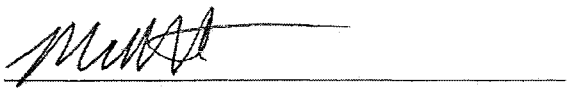
8. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

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

ACCEPTED AND AGREED this 25th day of April, 2019.

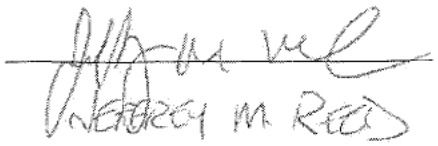
[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

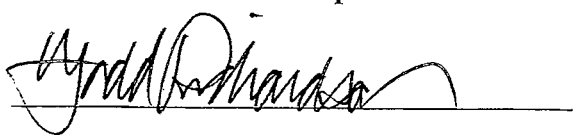


Michael Hooper
Senior Vice President
Regulatory, Legislative Affairs and Strategy

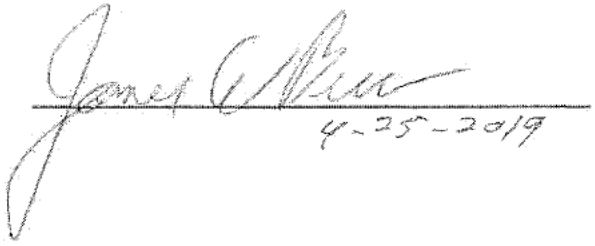
Indiana Office of Utility Consumer Counselor



NIPSCO Industrial Group



NLMK Indiana



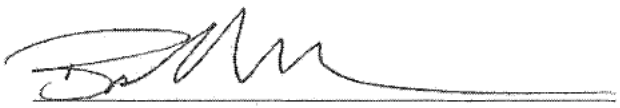
United States Steel Corporation



Citizens Action Coalition of Indiana, Inc.



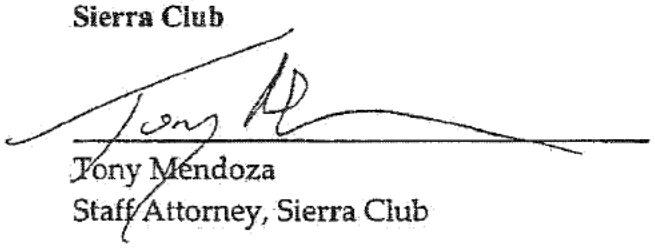
Walmart Inc.



Northern Indiana Commuter Transportation District

By _____
James A. L. Buddenbaum
One of Its Attorneys

Sierra Club



Tony Mendoza
Staff Attorney, Sierra Club

FILED
May 17, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 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

SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831 IMPLEMENTATION

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, on behalf of itself and NIPSCO Industrial Group; NLMK Indiana; and United States Steel Corporation (collectively the "Rate 831 Settling Parties"), respectfully submits the attached Stipulation and Settlement Agreement on Rate 831 Implementation (the Rate 831 Implementation Agreement"). The Rate 831 Implementation Agreement resolves the implementation of Rate 831, including

the proposed revenue allocation to Rate 831. The Rate 831 Settling Parties would propose that any party wishing to file testimony in response to the Rate 831 Implementation Agreement do so by June 7, 2019, to allow for the remainder of the procedural schedule to remain unchanged.

Respectfully submitted on behalf of the Rate 831 Settling Parties,

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Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic transmission this 17th day of May, 2019 to:

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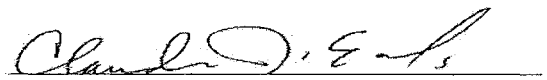
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Claudia J. Earls

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND, 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**

STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831 IMPLEMENTATION

This Stipulation and Settlement Agreement on Rate 831 Implementation ("Rate 831 Implementation Agreement") is entered into this 17th day of May, 2019, by and between Northern Indiana Public Service Company LLC ("NIPSCO"); the NIPSCO Industrial Group[1] ("Industrial Group"); NLMK Indiana ("NLMK");[2] and United States Steel Corporation ("US. Steel") (collectively the "Rate 831 Settling Parties"), who stipulate and agree for purposes of settling issues related to Rate 831, presented in this Cause, that the terms and conditions set forth below represent a fair and reasonable resolution subject to incorporation into a Final Order of the Indiana Utility Regulatory

[1] The Industrial Group is comprised of Accurate Castings, Inc., ArcelorMittal USA, BP Products North America, Inc., Cargill, Inc, Enbridge Energy, Praxair, Inc., and USG Corporation.

[2] NLMK joins in and supports this Rate 831 Implementation Agreement except as to paragraph C.4.

Commission ("Commission") without any modification or condition that is not acceptable to the Rate 831 Settling Parties.

A. Background

WHEREAS, NIPSCO filed a Verified Petition initiating this Cause on October 31, 2018 requesting, among other relief, approval of an Alternative Regulatory Plan pursuant to Indiana Code §8-1-2.5-6 that would facilitate a new service structure for industrial rates ("Rate 831") to address a changing energy landscape;

WHEREAS, the Rate 831 Settling Parties filed testimony explaining the operation of Rate 831 and supporting the need for Rate 831 to preserve NIPSCO's large industrial load, to retain the contribution of such load to fixed production costs, and support NIPSCO's resource planning;

WHEREAS, the Rate 831 Settling Parties filed testimony supporting the allocation methodology proposed by NIPSCO which would have produced cost-of-service rates for customers on Rate 831 while preserving a sizable subsidy for customers on Rate 811;

WHEREAS, the Rate 831 Settling Parties and other parties, including the Indiana Office of Utility Consumer Counselor, entered into and filed a Stipulation and Settlement Agreement On Less than All the Issues ("Revenue Settlement") with the Commission on April 26, 2019 which, among other matters, decreased NIPSCO's proposed revenue requirement by approximately $63.648 Million from the amount originally requested by NIPSCO;

WHEREAS, the Revenue Settlement indicated that parties would continue discussions in an effort to resolve revenue allocation and issues related to Rate 831;

WHEREAS, after negotiations conducted prior to and after the filing of the Revenue Settlement, the parties have been unable to resolve their differences on revenue allocation and issues related to Rate 831;

WHEREAS, the Rate 831 Settling Parties have been able to reach mutual agreement on issues related to Rate 831 implementation between and among themselves including rate design which will obviate the need for additional proceedings on such issues, including the Step 2 True Up, and wish to present the other parties and the Commission with an agreement to be considered as in the public interest for approval without modification;

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

B. Settlement Terms

1. Allocation: The Rate 831 Settling Parties[3] agree that NIPSCO's cost of service study should be used to allocate costs to Rate 831 based on a Tier 1 subscription of 194.556 megawatts. The Rate 831 Settling Parties agree that $149.438 Million (exclusive of approximately $2.827 Million in "other revenues") shall be allocated to Rate 831.

[3] US Steel submitted testimony in this Cause only related to Rate 831, and thus supports the settlement cost of service study as it relates to the rates, charges and trackers related to Rate 831, and takes no position on the remaining rate design.

2. Tracker Allocations:

a. The Rate 831 Settling Parties agree that Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (updated for the settlement revenue requirement and the adjustment for Rate 844), shall be used for purposes of establishing the allocation factors for NIPSCO's surviving tracker mechanisms.

b. The Rate 831 Settling Parties agree that Rate 831 Implementation Agreement Exhibit B, which is Attachment 19-R-E to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (with no changes), sets out the applicable portions of Rate 831 that are subject to each surviving tracking mechanism.

c. For the purposes of recovery of any approved capital transmission, distribution, and storage system improvement charge ("TDSIC") expenditures and costs, only Rate 831 customers' Tier 1 load constitutes "firm load" and the TDSIC revenue allocation shall only be applied to revenue associated with Rate 831 customers' Tier 1 load. The Rate 831 Settling Parties agree that Pages 5 and 6 of Rate 831 Implementation Agreement Exhibit A, which is Attachment 19-R-F to NIPSCO Witness Westerhausen's Verified Rebuttal Testimony (updated with the settlement revenue requirement) reflect the allocation factors for TDSIC purposes.

3. Rate 831 Rate Design:

a. Except as otherwise provided herein, the Rate 831 Settling Parties agree that Rate 831 shall be adopted as proposed in NIPSCO's case-in-chief as modified in NIPSCO's rebuttal, and based on the settlement revenue requirement for Rate 831 described in B.1., above.

b. The Rate 831 Settling Parties agree that the design of Rate 831 should be based on the cost of service study presented by NIPSCO as modified on rebuttal, and applying the settlement revenue requirement for Rate 831 described in B.1., above.

c. For purposes of the "Adjacent Affiliate Qualified Facility Premise Transmission Charge" the Rate 831 Settling Parties agree that the provision shall be amended by adding the following language: " If the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred between premises will be determined by the aggregate amount of self-generated Energy in excess of metered consumption in the applicable monthly billing period."

d. The Rate 831 Settling Parties agree that the amount of Tier 1 demand subscribed to by each of the Rate 831 customers and their corresponding Tier 1 energy in the initial 5-year contract is set forth in Rate 831 Implementation Agreement Confidential Exhibit C. The Rate 831 Settling Parties agree that the Tier 1 subscriptions

reflected in Rate 831 Implementation Agreement Confidential Exhibit C shall be binding upon each customer in the event of the approval of this Agreement without modification.

e. The Rate 831 Settling Parties agree that a transition period, lasting from the date on which Phase I rates become effective until June 1, 2020, shall provide Rate 831 customers time to make arrangements for their Tier 2 and Tier 3 energy and capacity needs. The Rate 831 Settling Parties agree that the terms and conditions set forth in Rate 831 Implementation Agreement Exhibit D shall be applicable to that transition period.

C. Procedural Aspects and Presentation of the Agreement

1. The Rate 831 Settling Parties acknowledge that a significant motivation to enter into this Rate 831 Implementation Agreement is the expectation that, if the Commission finds this Agreement to be reasonable and in the public interest, a Final Order approving the Agreement and authorizing the implementation of the Rate 831 service structure will be effective immediately, without the need for a Stage 2 True Up proceeding. The Rate 831 Settling Parties have spent considerable and valuable time reviewing data and negotiating the Agreement in an effort to eliminate time consuming and costly litigation. The Rate 831 Settling Parties agree to request that the Commission review this Agreement within the existing procedural schedule, and that if the Commission finds the Agreement to be reasonable and in the public interest, to approve the Agreement without any material modification in sufficient time to allow the Rate 831

service structure to be implemented contemporaneously with the all other changes in rates and charges.

2. The Rate 831 Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding, and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

3. If the Agreement is not approved in its entirety by the Commission, the Rate 831 Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding. Moreover, the concurrence of the Rate 831 Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without modification of material condition deemed unacceptable to any Settling Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that contains any unacceptable modifications.

4. In the event the Commission rejects this Settlement Agreement or the Alternative Regulatory Plan for Rate 831, or makes modifications in the Rate 831 allocation or design (collectively "831 Rejection"), which results in the six largest industrial customers being unable or unwilling to subscribe to the total megawatts included on Rate 831 Implementation Agreement Confidential Exhibit C under the proposed design, the Settling Parties agree that further proceedings in this Cause are

appropriate. In the event of 831 Rejection, the Settling Parties propose to notify the Commission so that a procedural schedule may be established to determine the proper rate structure for NIPSCO's largest industrial customers. The Rate 831 Settling Parties agree that the revenue requirement in the Revenue Settlement is calculated based upon NIPSCO's proposed change in its industrial service structure (i.e., establishing Rate 831). 831 Rejection would directly affect the stipulated revenue requirement, specifically the fuel and related expenses such that the revenue requirement will need to be revised and the allocated cost of service study will need to be revised, and that NIPSCO cannot implement new rates for any customer class until the additional proceeding is concluded.

5. The Rate 831 Settling Parties agree that this Agreement and each term, condition, amount, methodology, and exclusion contained herein reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology, or exclusion in any future proceeding. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, the Rate 831 Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, and the Final Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Rate 831 Settling Parties has entered into this Agreement solely to avoid future disputes and litigation with attendant inconvenience and expense.

6. The Rate 831 Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provides an adequate evidentiary basis upon which the Commission can make any finding of fact and conclusion of law necessary for the approval of this Agreement as filed. The Rate 831 Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

7. The issuance of a Final Order by the Commission approving this Agreement without any material modification or further condition shall terminate all proceedings in this Cause.

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

9. The Rate 831 Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement and the Rate 831 Settling Parties shall oppose any appeal of any portion of the Final Order approving this Agreement.

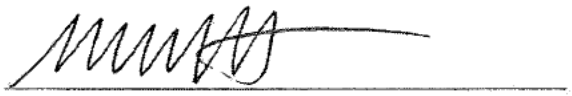
10. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

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

ACCEPTED AND AGREED this 17th day of May, 2019.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

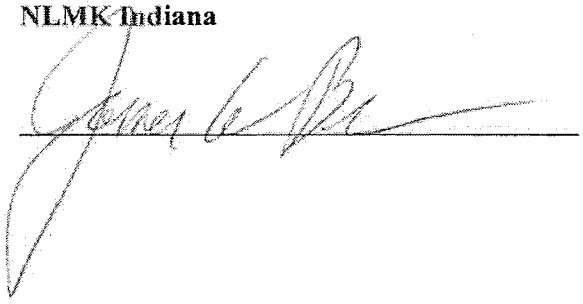


Michael Hooper
Senior Vice President
Regulatory, Legislative Affairs and Strategy

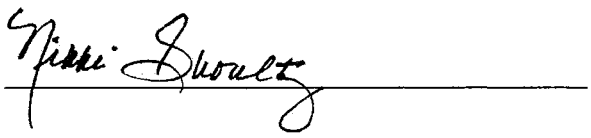
NIPSCO Industrial Group



NLMK Indiana



United States Steel Corporation



Tracker Allocators
2018 Electric Rate Case
Demand Allocation

Line	Description	Rate Class	Demand Allocators - Total Revenue	Rate 831 Tier 1 Adjustment	Revised Revenue	Resulting % Allocation on Revenue"
1	Residential	Rate 811	$ 508,397,289		$ 508,397,289	35.05%
2	C&GS Heat Pump	Rate 820	$ 914,117		$ 914,117	0.06%
3	GS Small	Rate 821	$ 253,812,406		$ 253,812,406	17.50%
4	Comml SH	Rate 822	$ 1,211,193		$ 1,211,193	0.08%
5	GS Medium	Rate 823	$ 165,705,139		$ 165,705,139	11.42%
6	GS Large	Rate 824	$ 207,833,587		$ 207,833,587	14.33%
7	Metal Melting	Rate 825	$ 7,273,007		$ 7,273,007	0.50%
8	Off-Peak Serv.	Rate 826	$ 121,033,845		$ 121,033,845	8.34%
9	Industrial Power Service - Large	Rate 831	$ -			
10	Tier 1	Tier 1	$ 152,266,583	$ (31,546,292)	$ 120,720,291	8.32%
11	Small Industrial Service - LLF	Rate 832	$ 12,790,750		$ 12,790,750	0.88%
12	Small Industrial Service - HLF	Rate 833	$ 28,801,612		$ 28,801,612	1.99%
13	Muni. Power	Rate 841	$ 3,500,918		$ 3,500,918	0.24%
14	Int WW Pumping	Rate 842	$ 111,123		$ 111,123	0.01%
15	Railroad	Rate 844	$ 2,146,284		$ 2,146,284	0.15%
16	Street Lighting	Rate 850	$ 7,896,064		$ 7,896,064	0.54%
17	Traffic Lighting	Rate 855	$ 910,582		$ 910,582	0.06%
18	Dusk to Dawn Lighting	Rate 860	$ 2,615,562		$ 2,615,562	0.18%
19		Interdepartmental	$ 4,946,681		$ 4,946,681	0.34%
20	System Total		$ 1,482,166,742		$ 1,450,620,450	100.00%

Tracker Allocators
2018 Electric Rate Case
Demand Allocation Support

Rate 831

Line No.	Description	Billing Determinants (kWh, kW)	Proposed Rate	Revenue	Total Revenue	Tier 1 Revenue
	Billed kW					
1	Firm Contract Demand	2,334,672	$ 22.97	$ 53,617,496	$ 53,617,496	$ 53,617,496
2						
3	Total kW	2,334,672		$ 53,617,496	$ 53,617,496	
	Energy Charge					
4	Variable O&M	1,534,532,236	$ 0.003435	$ 5,270,461	$ 5,270,461	$ 5,270,461
5	Fuel	1,684,938,526	$ 0.026446	$ 44,559,646	$ 44,559,646	$ 44,559,646
6	Transmission Charge	5,031,239,483	$ 0.008573	$ 43,132,596	$ 43,132,596	$ 14,444,904
	Adjacent Qualifying Facility Premise					
7	Transmission Charge	1,222,643,106	$ 0.002572	$ 3,144,500	$ 3,144,500	$ -
8	Transmission Charge Subtotal	6,253,882,589		46,277,096		
9	Total Energy Charge			$ 96,107,204	$ 96,107,204	$ 117,892,508
10	Other Revenue					$ 2,827,783
	Discounts - Billed kW					
11	Lagging RKVA Discount	(893,436)	$ 0.32	$ (285,900)	$ (285,900)	
12	Total Discount	(893,436)		$ (285,900)	$ (285,900)	
13	Industrial Power Service - Large (Rate 831)			$ 149,438,800	$ 149,438,800	$ 149,438,800
14	Other Revenue / Rate 831 Tier 1 Adjustment				$ 2,827,783	$ 31,546,292
15	Total				$ 152,266,583	

			%
Transmission kWh		5,031,239,483	100.00%
Adjacent Qualifying Facility Premise Transmission kWh	1,222,643,106	-	0.00%
Total		5,031,239,483	

Tracker Allocators
2018 Electric Rate Case
Demand Allocation Support

Description	Rates	Demand Allocators - Total Revenue	Rate 831 Tier 1 Adjustment	Revised Revenue	Resulting % Allocation on Revenue"
Residential	Rate 811	$ 508,397,289		$ 508,397,289	35.05%
C&GS Heat Pump	Rate 820	$ 914,117		$ 914,117	0.06%
GS Small	Rate 821	$ 253,812,406		$ 253,812,406	17.50%
Comml SH	Rate 822	$ 1,211,193		$ 1,211,193	0.08%
GS Medium	Rate 823	$ 165,705,139		$ 165,705,139	11.42%
GS Large	Rate 824	$ 207,833,587		$ 207,833,587	14.33%
Metal Melting	Rate 825	$ 7,273,007		$ 7,273,007	0.50%
Off-Peak Serv.	Rate 826	$ 121,033,845		$ 121,033,845	8.34%
Industrial Power Service - Large	Rate 831				
Tier 1	Tier 1	$ 152,266,583	$ (31,546,292)	$ 120,720,291	8.32%
Small Industrial Service - LLF	Rate 832	$ 12,790,750		$ 12,790,750	0.88%
Small Industrial Service - HLF	Rate 833	$ 28,801,612		$ 28,801,612	1.99%
Muni. Power	Rate 841	$ 3,500,918		$ 3,500,918	0.24%
Int WW Pumping	Rate 842	$ 111,123		$ 111,123	0.01%
Railroad	Rate 844	$ 2,146,284		$ 2,146,284	0.15%
Street Lighting	Rate 850	$ 7,896,064		$ 7,896,064	0.54%
Traffic Lighting	Rate 855	$ 910,582		$ 910,582	0.06%
Dusk to Dawn Lighting	Rate 860	$ 2,615,562		$ 2,615,562	0.18%
	Interdepartmental	$ 4,946,681		$ 4,946,681	0.34%
System Total		$ 1,482,166,742		$ 1,450,620,450	100.00%

Tracker Allocators
2018 Electric Rate Case
Energy Allocation

Line	Description	Rate Class	MWH at the Source	% Allocation on Sales
1	Residential	Rate 811	3,574,056	28.86%
2	C&GS Heat Pump	Rate 820	10,918	0.09%
3	GS Small	Rate 821	1,692,423	13.67%
4	Comml SH	Rate 822	12,282	0.10%
5	GS Medium	Rate 823	1,324,381	10.69%
6	GS Large	Rate 824	1,925,038	15.54%
7	Metal Melting	Rate 825	97,218	0.78%
8	Off-Peak Serv.	Rate 826	1,327,574	10.72%
9	Industrial Power Service - Large	Rate 831		
		Tier 1	1,716,774	13.86%
		Tier 2	0	0.00%
10	Small Industrial Service - LLF	Rate 832	152,471	1.23%
11	Small Industrial Service - HLF	Rate 833	408,867	3.30%
12	Muni. Power	Rate 841	29,678	0.24%
13	Int WW Pumping	Rate 842	355	0.00%
14	Railroad	Rate 844	21,905	0.18%
15	Street Lighting	Rate 850	42,843	0.35%
16	Traffic Lighting	Rate 855	6,532	0.05%
17	Dusk to Dawn Lighting	Rate 860	15,291	0.12%
18		Interdepartmental	26,376	0.21%
19	System Total		12,384,981	100%

Tracker Allocators
2018 Electric Rate Case
TDSIC Allocation

Transmission and Distribution
Revenue Requirement Allocation

*For purposes of recovering approved capital TDSIC expenditures and costs pursuant to I.C. 8-1-39-9(a), the following class allocation factor percentages shall be applied to the respective distribution- or transmission-related revenue requirement and then the resulting TDSIC charge factors (per kWh) applied to each customer's firm (or non-interruptible) load within that class:

Line	Description	Rate Class	Transmission Rev. Req. Allocation Factor %	Distribution Rev. Req. Allocation Factor %
1	Residential	Rate 811	36.65%	53.48%
2	C&GS Heat Pump	Rate 820	0.11%	0.19%
3	GS Small	Rate 821	15.95%	17.65%
4	Comml SH	Rate 822	0.12%	0.18%
5	GS Medium	Rate 823	11.67%	9.90%
6	GS Large	Rate 824	13.82%	10.77%
7	Metal Melting	Rate 825	0.48%	0.53%
8	Off-Peak Serv.	Rate 826	8.49%	5.98%
9	Industrial Power Service - Large	Rate 831	8.55%	0.00%
10	Small Industrial Service - LLF	Rate 832	1.05%	0.00%
11	Small Industrial Service - HLF	Rate 833	2.26%	0.00%
12	Muni. Power	Rate 841	0.25%	0.33%
13	Int WW Pumping	Rate 842	0.00%	0.00%
14	Railroad	Rate 844	0.14%	0.00%
15	Street Lighting	Rate 850	0.07%	0.27%
16	Traffic Lighting	Rate 855	0.04%	0.03%
17	Dusk to Dawn Lighting	Rate 860	0.04%	0.20%
		Interdepartmental	0.31%	0.50%
18	System Total		100.00%	100.00%

Tracker Allocators
2018 Electric Rate Case
TDSIC Allocation Support

TDISC Allocators

Rate	Trans	Sub Trans	Total	831 Tier 1 Adj	Adj. Total	Transmission Rev. Req. Allocation Factor
Rate 811	$ 40,202,805	$ 9,738,719	$ 49,941,524		$ 49,941,524	36.65%
Rate 820	$ 106,041	$ 45,896	$ 151,937		$ 151,937	0.11%
Rate 821	$ 17,869,739	$ 3,858,926	$ 21,728,665		$ 21,728,665	15.95%
Rate 822	$ 122,851	$ 43,518	$ 166,369		$ 166,369	0.12%
Rate 823	$ 13,545,126	$ 2,362,188	$ 15,907,314		$ 15,907,314	11.67%
Rate 824	$ 16,052,377	$ 2,778,410	$ 18,830,787		$ 18,830,787	13.82%
Rate 825	$ 471,091	$ 176,362	$ 647,453		$ 647,453	0.48%
Rate 826	$ 9,953,037	$ 1,618,947	$ 11,571,984		$ 11,571,984	8.49%
Rate 831	$ 46,812,162	$ 778,690	$ 47,590,853	24.48%	$ 11,651,965	8.55%
Rate 832	$ 1,295,072	$ 141,359	$ 1,436,432		$ 1,436,432	1.05%
Rate 833	$ 2,954,176	$ 119,153	$ 3,073,328		$ 3,073,328	2.26%
Rate 841	$ 266,805	$ 73,950	$ 340,755		$ 340,755	0.25%
Rate 842	$ 2,535	$ 336	$ 2,871		$ 2,871	0.00%
Rate 844	$ 124,451	$ 62,044	$ 186,495		$ 186,495	0.14%
Rate 850	$ 38,830	$ 61,938	$ 100,767		$ 100,767	0.07%
Rate 855	$ 51,320	$ 7,114	$ 58,433		$ 58,433	0.04%
Rate 860	$ 18,423	$ 31,541	$ 49,964		$ 49,964	0.04%
Interdepartmental	$ 300,492	$ 123,169	$ 423,661		$ 423,661	0.31%
Total	$ 150,187,333	$ 22,022,260	$ 172,209,593		$ 136,270,706	100%

Tier 1 Transmission Volumes	1,534,532,236	24.48%
Total Transmission Volumes'	6,267,586,326	

Rate	Dist Primary	Dist Secondary	Total	Distribution Rev. Req. Allocation Factor
Rate 811	$ 79,507,533	$ 32,262,948	$ 111,770,481	53.48%
Rate 820	$ 374,700	$ 17,911	$ 392,612	0.19%
Rate 821	$ 31,431,404	$ 5,458,155	$ 36,889,559	17.65%
Rate 822	$ 355,284	$ 26,207	$ 381,491	0.18%
Rate 823	$ 19,272,477	$ 1,419,524	$ 20,692,002	9.90%
Rate 824	$ 21,864,911	$ 639,198	$ 22,504,109	10.77%
Rate 825	$ 1,077,024	$ 27,080	$ 1,104,104	0.53%
Rate 826	$ 12,110,993	$ 394,245	$ 12,505,238	5.98%
Rate 831	$ -	$ -	$ -	0.00%
Rate 832	$ 0	$ -		0.00%
Rate 833	$ (0)	$ -	$ (0)	0.00%
Rate 841	$ 603,733	$ 81,096	$ 684,828	0.33%
Rate 842	$ 2,744	$ 763	$ 3,507	0.00%
Rate 844	$ -	$ -	$ -	0.00%
Rate 850	$ 505,664	$ 53,048	$ 558,712	0.27%
Rate 855	$ 58,075	$ 6,859	$ 64,934	0.03%
Rate 860	$ 257,503	$ 159,191	$ 416,694	0.20%
Interdepartmental	$ 1,005,562	$ 31,466	$ 1,037,029	0.50%
Total	$ 168,427,607	$ 40,577,693	$ 209,005,300	100.00%

NORTHERN INDIANA PUBLIC SERVICE COMPANY **Original Sheet No. 201**
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Sheet No. 1 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 870	FAC	Adjustment of Charges for Cost of Fuel Rider	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 871	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 874	RA	Adjustment of Charges for Resource Adequacy	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 876	BMTIS	Back-Up and Maintenance Industrial Service Rider	831
Rider 877	EDR	Economic Development Rider	824, 826, 832, 833
Rider 878	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	811, 820, 821, 822, 823, 824, 825, 826, 832, 833, 841, 844,
Rider 879	IS	Interconnection Standards	811, 820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, 844, 865
Rider 880	NM	Net Metering	811, 820, 821, 822, 823, 824, 825, 826, 832, 833, 841

NORTHERN INDIANA PUBLIC SERVICE COMPANY **Original Sheet No. 202**
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 881	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	823, 824, 825, 826, 831, 832, 833
Rider 882	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	823, 824, 825, 826, 831, 832, 833
Rider 883	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 844, Rider 876
Rider 886	GPR	Green Power Rider	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, and Rider 876
Rider 887	FMCA	Adjustment of Charges for Federally Mandated Costs	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 888	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

Original Sheet No. 201~~87~~

APPENDIX A
APPLICABLE RIDERS

Sheet No. 1 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 870	FAC	Adjustment of Charges for Cost of Fuel Rider	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 871	RTO	Adjustment of Charges for Regional Transmission Organization Adjustment	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 874	RA	Adjustment of Charges for Resource Adequacy	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 876	BMTIS	Back-Up and Maintenance Industrial Service Rider	831
Rider 877	EDR	Economic Development Rider	824, 826, ~~830~~832, 833
Rider 878	COG	Purchases from Cogeneration Facilities and Small Power Production Facilities	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 832, 833, 841, 844,
Rider 879	IS	Interconnection Standards	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831, 832, 833, 841, 844, 865
Rider 880	NM	Net Metering	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 832, 833, 841

Issued Date
__/__/2019

Effective Date
6/30/2019

NIPSCO®

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

Original Sheet No. 202~~188~~

APPENDIX A
APPLICABLE RIDERS

Sheet No. 2 of 2

Rider	Code	Rider Name	Applicable Tariffs
Rider 881	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	823, 824, 825, 826, ~~830,~~ 831, 832, 833
Rider 882	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	823, 824, 825, 826, ~~830,~~ 831, 832, 833
Rider 883	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 844, Rider 876
Rider 886	GPR	Green Power Rider	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, and Rider 876
Rider 887	FMCA	Adjustment of Charges for Federally Mandated Costs	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876
Rider 888	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	811, 820, 821, 822, 823, 824, 825, 826, ~~830,~~ 831 Tier 1, 832, 833, 841, 842, 844, 850, 855, 860, Rider 876

Issued Date
__/__/2019

Effective Date
6/30/2019

NIPSCO

Rate 831 Implementation Agreement Confidential Exhibit C (Redacted)
Cause No. 45159

1. Tier 2 and/or Tier 3 Contract Terms.

The Rate 831 Settling Parties agree that any contract for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions:

(a) identify NIPSCO as the Market Participant for the retail customer at Midcontinent Independent System Operator, Inc. ("MISO");

(b) reference NIPSCO's market-based rate authority with Federal Energy Regulatory Commission ("FERC");

(c) clearly state the Rate 831 customer remains a retail customer of NIPSCO;

(d) indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations);

(e) incorporate relevant provisions of the Rate 831 tariff;

(f) all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and

(g) any information shared with NIPSCO shall be subject to a confidentiality agreement applicable to all other terms of said agreements.

2. Rate Implementation Dates.

The Rate 831 Settling Parties agree that the customer's elections under Rate 831 Tiers 2 and/or Tier 3 shall occur in a window between the day after NIPSCO's compliance filing in this Cause to thirty (30) days thereafter. Customer recognizes that in

order to implement Tier 3, customer may need to install software including a security certificate to be provided by NIPSCO. The parties agree to work together during the 30 day period to achieve implementation.

3. Firm Capacity Transactions.

NIPSCO agrees that under either Tier 2 or Tier 3, a customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges.

4. Dispute Resolution.

NIPSCO agrees that the third party energy and capacity supplier may represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the Indiana Utility Regulatory Commission. At a minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 104
NIPSCO 2023 Rate Order

This document was published in full (including pages with the word "Confidential" beginning on page 110) on the website of the Indiana Utility Regulatory Commission on August 2, 2023.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

ORDER OF THE COMMISSION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

According to Mr. Eckert, if approved, the Settlement Agreement will provide certainty regarding critical issues, including revenue requirements, authorized return, and the allocation of NIPSCO's revenue requirement among its various rate classes. Pub. Ex. 16 at 2. Mr. Gorman

testified that despite the number of complex issues in the case and the parties' sometimes divergent views on those issues, they were able to reach resolution of the case, as well as two other pending matters that impacted NIPSCO's rates, through the negotiation process. IG Ex. 6 at 6.

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

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

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

Ms. Whitehead noted that the Settling Parties agree that NIPSCO's base rates will be designed to produce the gross revenue amount of $1,767,260,404 prior to application of surviving Riders, plus amounts NIPSCO will recover through the new ECT, which relates to NOx emissions allowances and variable chemical costs at NIPSCO's coal-fired generating stations. These ECT costs are forecasted to be approximately $30 Million per year. Pet. Ex. 2-S at 3-4. Industrial Group Witness Dauphinais testified that the remaining $72 Million that NIPSCO originally proposed to include in its new tracker would remain embedded in base rates, and allocated between classes on

the same basis as those costs were allocated in Cause No. 45159. IG Ex. 7 at 9. Ms. Whitehead explained that under the Settlement Agreement, the total increase in base rates plus the forecasted ECT results in a revenue increase from current base rates of approximately $291.8 Million. This results in a reduction of approximately $103.2 Million from the amount NIPSCO originally requested in its case-in-chief. Pet. Ex. 2-S at 4.

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

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

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

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

The Settlement Agreement provides that NIPSCO's base rates will be designed to produce $1,767,260,404 prior to application of surviving Riders plus the new ECT. The increase in base rates, plus the forecasted ECT, results in an increase from current base rates of approximately $291,804,809. This increase is a decrease of approximately $103,205,168 from the amount

originally requested by NIPSCO in its case-in-chief. The agreed-upon revenue requirement reflects the depreciation study and accrual rates and amortization provided in the Settlement Agreement. The stipulated revenue requirement is calculated to produce an authorized net operating income ("NOI") of $402,900,940. NIPSCO Witness Shikany described the Step 2 revenue requirement and sponsored the supporting schedules. Pet. Ex. 3-S.

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

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

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

In its case-in-chief, NIPSCO had proposed a 10.4% ROE and several intervenors, including the OUCC and Industrial Group, advocated for a considerably lower ROE. The testimony in support of the Settlement Agreement explained that as a result of the negotiations, a compromise was reached, resulting in a 9.80% ROE. The Settlement Agreement ROE is within the range of ROE originally recommended for NIPSCO by Mr. Gorman (i.e., 9.00% to 9.90%). Mr. Gorman testified that 9.80% was reasonable for NIPSCO given the balance of the compromises reflected in the Settlement Agreement. IG Ex. 1 at 3. NIPSCO Witness Whitehead explained that if NIPSCO's ROE is set too low, it could lead to financial insecurity that would place increased risk on NIPSCO's ability to attract capital, which could also challenge NIPSCO's ability to obtain the

capital necessary to continue to provide safe, reliable, and affordable service to its electric customers. Pet. Ex. 2-S at 4. Mr. Eckert testified that the OUCC found the agreed ROE reasonable and in the interest of ratepayers. Further, the ROE component of the weighted average cost of capital used in each of NIPSCO's capital riders will be 9.80%. Pub. Ex. At 5.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FERC Account 108 states:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The ECT filing methodology and frequency was described by NIPSCO Witness Blissmer. The filing will be semi-annual and based upon actual historical costs. The charge will be calculated on a per kWh basis (except for Rate 526 per the Settlement Agreement). Actual costs recovered through the rider would be deferred commencing with the approval of Step 1 rates until they are recovered through the rider. The first filing is expected to be in March 2024, seeking to recover

costs incurred from the effective date of Step 1 rates through December 31, 2023. This first rider would be expected to take effect in July 2024. The second filing would then be in September 2024, recovering actual costs incurred from January 1, 2024 through June 30, 2024. The filings would follow semiannually in March and September thereafter. Pet. Ex. 4 at 33-34.

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

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

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

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

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

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

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

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

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

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

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

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

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

NIPSCO Witness Taylor presented the settlement revenue apportionment and class rate increases in Attachment 19-S-A. Pet. Ex. 19-S. Table 1 in his settlement testimony shows the mitigation of interclass subsidies from NIPSCO's case-in-chief proposal to the Settlement. *Id.* at 5. He also presented Attachment 19-S-B which shows detailed calculations for each rate component of each Rate Schedule, as well as how the targeted total rate schedule revenue will be

achieved using the proposed rates and volumes. Further, Attachment 19-S-B provides a presentation of the transition of revenues at current rates and existing 800 series rate classes to the proposed revenues at the 500 series rate classes. Mr. Taylor also presented Attachment 19-S-D as a new version of Attachment 19-H from his direct testimony which provides the updated tracker allocators that result from the Settlement changes to cost of service and revenue mitigation.

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

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

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

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

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

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

(c) the starting point is the proposed Rate 531 tariff terms and conditions, 180 MW of allocated Rate 531 class demand, and 170 MW of aggregate contract demand. The eventual end

point, based on the current composition of the class, is 70 MW of both Tier 1 class demand and actual contract demand, with future proportional adjustments reducing the starting 110 MW differential between the class demand and the end point;

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

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

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

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

The provisions relating to Rate 531 were further supported by settlement testimony from current Rate 831 customers. Mr. Dauphinais testified the terms largely preserve the status quo, with modest reductions in Tier 1 commitments and a closer alignment between cost-allocation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

8. <u>Opposition to Settlement Agreement</u>. Mr. O'Connell testified as to MIUG's opposition to the Settlement Agreement. MIUG Ex. 3. He explained what he considered to be arbitrary barriers in the proposed Rates 532 and 533 because they were created without a clear methodology and are primarily the result of past NIPSCO rate case settlements. He said these arbitrary barriers directly cause certain transmission customers to pay significant premiums on their electric services by forcing them on to the proposed Rate 526 services. He said the proposed Rate 526 and current Rate 826 allocates distribution system charges to at least two transmission customers who are not connected to NIPSCO's distribution system; whereas, the proposed Rates 531, 532 and 533 only allocate transmission and sub-transmission charges to similarly situated transmission customers. He explained, using cost causation principles, NIPSCO should not allocate its distribution system costs to any transmission-only customers, as these customers do not benefit from NIPSCO's distribution system, nor were they the direct or proximate cause for the development of the distribution system. He also said, under the proposed Rate 526, a

hypothetical transmission customer with a peak demand of less than 10,000 kW will be allocated significant distribution service charges, while a similarly situated customer on the proposed Rates 531, 532, or 533 who happens to have a peak demand of over 10,000 kW will pay no such distribution service charges.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Despite the complexity and number of issues raised in this proceeding, the Settling Parties reached a comprehensive agreement, as reflected in the Settlement Agreement filed in this proceeding. Although it is opposed by two parties, those joining or not opposing the Settlement Agreement and Addenda represent a wide variety of interests and types of customers, including residential, commercial, and industrial customers. A complete copy of the terms and conditions of the Settlement Agreement can be found in Attachment A to this Order (Jt. Ex. 1), while the new

depreciation rates are set forth in Attachment B (Pet. Ex. 3-S, Attach. 3-F-S) and the Redacted Rate 831/531 Modification Settlement is attached as Attachment C (Pet. Ex. 2, Confidential Attach. 2-B). These attachments are incorporated into and made a part of this Order by reference.

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

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

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

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

two pending federal mandate cases, which is in addition to the base rate increase NIPSCO sought in its direct case. Jt. Ex. 1, Para. B.3.(a).

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

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

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

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

Additionally, in support of the Settlement Agreement, Ms. Whitehead explained that it represents more than a $100 Million decrease from NIPSCO's as-filed revenue requirement. This is in addition to certain mitigation steps that NIPSCO identified it had taken in its case-in-chief, including its proposed change in depreciation methodology. As she further testified, in total, these reductions in expense result in a large decrease in cash flow available to NIPSCO, thereby increasing NIPSCO's need to finance expenses and capital investments. The Settlement Agreement reflects NIPSCO's agreement to these various terms, which, from NIPSCO's point of view, link directly to the ultimate agreement on ROE. NIPSCO, its customers, and the Commission

all have an interest in ensuring NIPSCO's financial health, because failure to do so will increase NIPSCO's financing costs, causing an adverse impact on the ability to attract capital investment and on customer rates.

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

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

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

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

To begin with, the ARP implementing NIPSCO's Rate 831 industrial service structure was approved in Cause No. 45159 as part of a settlement that was distinct from the agreement on the revenue requirement. Here, the modifications sought to NIPSCO's ARP were contained in the Rate 831/531 Modification Settlement that was filed with NIPSCO's case-in-chief. Thus, in the Settlement Agreement pending before the Commission in this case, the Settling Parties were aware of the provisions of Rate 831/531 Modification Settlement as they presented their responsive cases and then negotiated the revenue requirement and other issues. Moreover, all the Settling Parties

either agreed that the Rate 831/531 Modification Settlement should be approved or agreed not to oppose it. As such, the Settling Parties had the opportunity to fully consider the effect of the Rate 831/531 Modification Settlement on this case and were able to take that agreement's impacts, including NIPSCO's resulting business risk, into consideration, when they agreed to an ROE of 9.80%.

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

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

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

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

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

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

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

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

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

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

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

45159 Order at 154-55.

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

3. Rates 532 and 533. MIUG also seeks to reduce the minimum demand thresholds for Rates 532 and 533 to 2 MW and to eliminate the requirement that the customer own the equipment necessary to reduce transmission voltage to the individual customer's voltage requirements. MIUG argues that, otherwise, customers served directly from the

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

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

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

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

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

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

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

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

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

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

Finally, the Commission found in Cause No. 45159 that the Rate 831 ARP satisfied the fourth statutory factor, insofar as traditional ratemaking impeded NIPSCO's ability to provide competitive rates for large industrial customers with demonstrated capability to exercise alternatives including self-supply, production shifts, and facility closures. *Id.* at 155-156. The

record here confirms the same conditions have continued, and the proposed modifications to the ARP support the function of Rate 531 to retain the class as retail load.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

APPROVED:

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

Dana Kosco
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

STIPULATION AND SETTLEMENT AGREEMENT

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

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

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

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

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

A. Background

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

provide safe, reliable, and adequate service to its customers. Rates need to be changed to properly reflect the effects of these drivers as soon as possible.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income:

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

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

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

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

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

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

(ii) NIPSCO's forecasted capital structure; and

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

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

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

3. Depreciation and Amortization Expense:

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

(i) The amortization period for retired coal-fired generating units and the regulatory assets resulting from regulatory accounting authorized

by the 45159 Rate Case Order shall conclude June 30, 2034. This produces a reduction of approximately $26.0 Million in depreciation expense and a reduction of an additional approximate $8.8 Million for the amortization of the regulatory asset resulting from the retirement of Schahfer Units 14 and 15.

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

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

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

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

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

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

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

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

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

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

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

(c) Future Cost of Removal and Regulatory Accounting:

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

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

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

4. Pro Forma Net Operating Income at Present Rates:

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

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

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

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

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

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

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

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

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

6. Phased Rate Implementation:

(a) Step 1 Rates Subject to Refund: Step 1 rates shall be implemented as soon as possible following the issuance of an Order in this Cause and will be based on actual net plant certified to have been completed and placed in service no later than June 30, 2023. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of June 30, 2023. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of June 30, 2023 and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the

amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of June 30, 2023. NIPSCO will provide all Parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All Parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of June 30, 2023, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on or about March 1, 2024 and will based on actual net plant certified to have been completed and placed in service no later than December 31, 2023. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2023. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2023 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have

been placed in service and are used and useful in providing utility service as of December 31, 2023. NIPSCO will provide all Settling Parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have sixty (60) days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

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

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

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

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

move to being subsidized by other rates. The provisions of this paragraph will be implemented in the cost of service and rates included with NIPSCO's settlement testimony, which will be submitted to the Commission by March 17, 2023.

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

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

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

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

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

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

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

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

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

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

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

information available to any member of this rate class and/or their consultants who request such information.

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

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

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

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

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

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

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

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

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

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

C. Procedural Aspects and Presentation of the Agreement

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

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

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

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

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

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

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

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

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

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

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

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

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

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Office of Utility Consumer Counselor

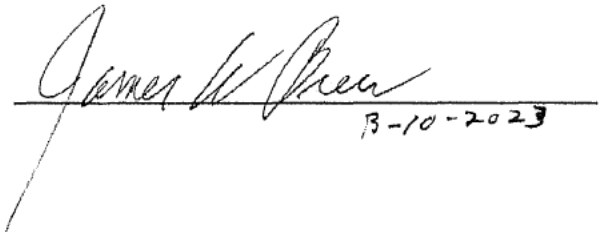


William Fine
Utility Consumer Counselor
Indiana Office of Utility Consumer Counselor
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204

NIPSCO Industrial Group



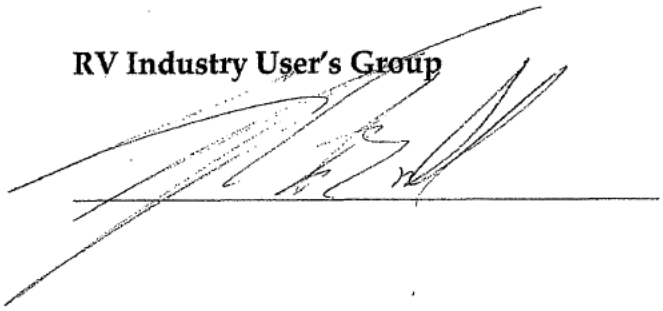
NLMK Indiana



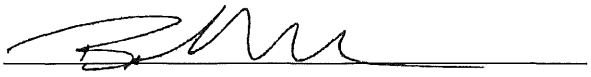
United States Steel Corporation

Kristina Ken Wheeler

RV Industry User's Group



Walmart Inc.



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

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

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

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

Footnote 1 - Unless otherwise noted

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

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

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

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

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

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

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

Cost of Investor Supplied Capital

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

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

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

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

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

Footnote 1 - Unless otherwise noted

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

Line No.	Description					Revenue Deficiency
1	Net Original Cost Rate Base					$ 5,925,013,822
2	Rate of Return					6.80%
3	Net Operating Income					$ 402,900,940
4	Pro forma Net Operating Income					$ 184,513,452
5	Increase in Net Operating Income (NOI Shortfall)					$ 218,387,488
6	Effective Incremental Revenuel NOI Conversion Factor					74.84%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)					$ 291,804,089
8	One		1.000000			
9	Less: Public Utility Fee		0.001276			
10	Less: Bad Debt		0.002565			
11	State Taxable Income			0.996159		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	-				
14	Taxable Adjusted Gross Income Tax		0.996159			
15	Adjusted Gross Income Tax Rate		0.049000			
16	Adjusted Gross Income Tax			0.048812		
17	Line 11 less line 13 less line 16				0.947347	
18	One			1.000000		
19	Less: Federal Income Tax Rate			0.210000		
20	One Less Federal Income Tax Rate				0.790000	
21	Effective Incremental Revenue / NOI Conversion Factor					74.840%

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

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

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

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
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4	Deferred Income Taxes	1,393,665,855	15.76%	0.00%	0.00%
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6	Prepaid Pension Asset	(424,946,780)	-4.81%	0.00%	0.00%
7	Post-1970 ITC	640,278	0.01%	7.67%	0.00%
8	Totals	**$ 8,841,620,445**	**100.00%**		**6.80%**

Cost of Investor Supplied Capital

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11	**Totals**	**$ 7,798,774,027**	**100.00%**		**7.67%**

Addendum A

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

1) IMUG will in writing not oppose the Settlement Agreement in Cause No. 45772. This includes IMUG and all Settling or not opposing Parties waiving cross-examination of all Settling Parties' witnesses, but IMUG reserves the right to ask questions of any witness that does appear and is crossed by a non-settling party, or crossed in a manner contrary to IMUG's benefits from this Settlement.
2) Streetlights provide essential important public service benefits through nighttime public safety and through promotion of nighttime economic development and social activities. Those public service benefits are further enhanced through the superior lighting provided by modern LED streetlights. NIPSCO's municipal electric customers are public services providers who pay for street lighting and an array of other essential public services through limited municipal budgets without profit motivation. Those municipal streetlight public service efforts primarily benefit and protect NIPSCO area residents. As such it is agreed that:
3) NIPSCO will fund energy efficiency audits and new efficiency measures including LEDs for each of the three participating municipality members of IMUG (as of March 3, 2023), at a maximum cost of up to $25,000 per municipality. NIPSCO will work with the IMUG members to choose a mutually agreeable company or consultant to perform these energy efficiency audits. If a program or project qualifies for NIPSCO's energy efficiency program, this will qualify as a "new energy efficiency measure" under this term, and the customer cost (after rebate) would qualify for reimbursement under this term. NIPSCO and the municipalities will work in good faith as to what qualifies as a "new energy efficiency measure."
4) The percentage increase to Rate 550 will not be greater than the percentage increase to Rate 511 as stipulated in Section 7 (l) of the Settlement Agreement.
5) NIPSCO will lend its expertise to any IMUG member that seeks to convert customer-owned streetlights to LEDs, e.g., meetings, exchange of info, sharing access to consultants for learning and knowledge, etc.
6) NIPSCO will work with IMUG to seek to improve its record keeping for LED and HPS street lighting so that the records will differentiate between the type of fixture (*e.g.*, LED, MV, HPS) and the type of repair made.

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

Addendum A

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

[SIGNATURE PAGES FOLLOW]

Addendum A

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Municipal Utility Group

Theodore J Sommer

Addendum B

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

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

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

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

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

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

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

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

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

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

RV Group TDSIC Project(s)

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

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

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

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

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

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

[SIGNATURE PAGES FOLLOW]

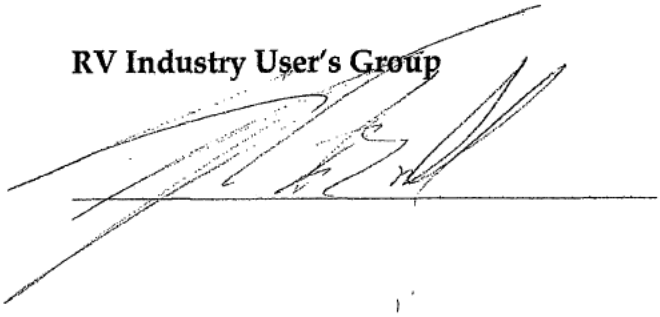
Addendum B

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Attachment A

RV Industry User's Group



NORTHERN INDIANA PUBLIC SERVICE COMPANY

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

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

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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

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

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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

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

Attachment B

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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

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

NORTHERN INDIANA PUBLIC SERVICE COMPANY

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

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

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

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

STIPULATION AND SETTLEMENT AGREEMENT ON RATE 831/531 MODIFICATION

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

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

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

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

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

A. Background

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

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

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

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

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

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

WHEREAS, in order to reduce the contested issues in NIPSCO's upcoming rate proceeding, the Rate 831 Settling Parties negotiated in advance of NIPSCO's filing and have reached mutual agreement on issues related to Rate 831 (which will be renumbered Rate 531) for purposes of that cause. The Settling Parties' agreement

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with respect to the Rate 831 issues to be presented in that cause is set forth in this Agreement, and it is the intent of the Rate 831 Settling Parties to file testimony supporting this Agreement as part of NIPSCO's upcoming rate proceeding; and

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

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

B. Settlement Terms

1. Scope of this Agreement:

The scope of this Agreement is limited to the Rate 831 Settling Parties' mutual agreement and understanding with respect to the modification of NIPSCO's ARP to reflect changes in allocation of costs between Rate 831 and Rate 531, including the use and approval of a 4 CP cost of service methodology for the allocation of production demand-related costs and a 12 CP cost of service methodology for the allocation of transmission demand-related cost, the agreed level of Tier 1 contract demand by the Rate 831 customers, the resulting design of rates for new Rate 531, and those other items expressly

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stated herein. Except as expressly stated herein, this Agreement does not provide for any further modifications to NIPSCO's ARP approved in Cause No. 45159 nor modifications to the existing Rate 831 tariff. The Rate 831 Settling Parties reserve all rights with respect to issues and positions not addressed in this Agreement, including, but not limited to, NIPSCO's revenue requirement, NIPSCO's proposals for modifications to the new Rate 531 tariff set forth in Section B.6. of this Agreement, non-Rate 831 or 531 specific rate proposals, and adjustments to NIPSCO's as-filed allocated cost of service study, provided that any such proposed adjustments to the allocated cost of service study do not propose alteration of the use of the 4 CP demand related production or 12 CP demand related transmission allocation methodologies.

2. Allocation:

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

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

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

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

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

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

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

3. Contract Term:

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

b. Rate 831 Increases in Tier 1 Demand. Any existing Rate 831 customer, or new Rate 531 customer, may increase Tier 1 firm

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contract demand or begin taking service under new Rate 531 in accordance with the existing Rate 831 tariff terms.

4. Tracker Allocations:

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

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

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

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

5. Rate 831 Rate Design:

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

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

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

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

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

6. Tariff Language:

The Rate 831 Settling Parties agree that the terms of this Agreement do not require any change or modification to the existing provisions of the Rate 831 tariff, except as expressly provided herein. NIPSCO has discussed two potential changes to existing Rate 831 beyond those presented in this Agreement, which relate to good faith efforts to provide updated load forecasts and potential modifications to

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reference MISO's proposed seasonal resource adequacy construct. However, as set forth in Section B.1. above, those provisions are outside the scope of this Agreement. Therefore, NIPSCO reserves the right to propose changes consistent with these two items, and the Rate 831 Settling Parties reserve the right to take any position with respect to these two items, and only these two items. In all other respects, the terms and provisions of the Rate 831 tariff shall be maintained intact in the new Rate 531, except as described herein.

C. Procedural Aspects and Presentation of the Agreement

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

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

a. For purposes of this Agreement, a material modification includes, but is not limited to, a modification to (i) production demand-related cost

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of service using 180 megawatts or rates designed using the contracted Tier 1 demand levels totaling 170 megawatts; (ii) the agreed-to contract term; (iii) 4 CP cost of service methodology for production-related demand-related cost; and (iv) 12 CP cost of service methodology for the allocation of transmission demand-related cost.

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

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

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

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

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

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

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

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

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

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

[SIGNATURE PAGES FOLLOW]

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Northern Indiana Public Service Company LLC



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NIPSCO Industrial Group



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

NLMK INDIANA

Nicholas Thomas 9.9.22

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United States Steel Corporation

Kristina Kern Wheeler

Pratt Paper (IN), LLC



Stephen Ward
Chief Financial Officer

Northern Indiana Public Service Company LLC
Modification Agreement Confidential Exhibit A

Customer	Contract Demand (MW)
[redacted]	
Total	170.0

Rate 831/531 Modification Agreement Exhibit B

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

APPENDIX A
APPLICABLE RIDERS

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

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NIPSCO

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

APPENDIX A
APPLICABLE RIDERS

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

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NIPSCO

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 105
DOE Order No. 202-08-1

The Secretary of Energy
Washington, DC 20585

Order No. 202-08-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Ike, large portions of the areas affected by the hurricane are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, CenterPoint Energy is authorized and directed to temporarily connect at distribution and transmission level voltages such as 12.5kV, 13.2kV, 25kV, 69kV, 138kV, and 230kV to restore power to Entergy Gulf States, Inc. as well as electric cooperatives and municipal customers within the State of Texas. Pursuant to section 202(d) of the FPA, 16 U.S.C. 824a(d), during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may, pursuant to this order, make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2008.

Issued in Washington, D.C. at 1600 this 14th day of September, 2008.

Samuel W. Bodman
Secretary of Energy

Printed on recycled paper

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 106
NIPSCO 2025 Rate Order

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	**)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)** **)**	**CAUSE NO. 46120** **APPROVED:**

ORDER OF THE COMMISSION

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

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On September 12, 2024, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below.[1] On that same day, Petitioner filed its case-in-chief, workpapers, and the information listed in the minimum standard filing requirements set forth at 170 IAC 1-5. NIPSCO's case-in-chief included testimony, attachments, and workpapers from the following witnesses:[2]

- Vincent A. Parisi, President and Chief Operating Officer, NIPSCO;
- Erin E. Whitehead, Vice President of Regulatory Policy and Major Accounts, NIPSCO;
- Richard D. Weatherford, Manager, Regulatory – Rate Case Execution, NiSource Corporate Services Company ("NCSC");
- Emily J. Bytnar, Manager of Rate Case Execution, NCSC;
- Nick Bly, Director of Accounting, NCSC;
- Patrick L. Baryenbruch, President, Baryenbruch & Company, LLC;
- Orville Cocking, Senior Vice President of Electric Operations, NIPSCO;
- Stephen Holcomb, Director of Environmental Policy & Sustainability, NCSC;
- Rosalva Robles, Manager of Planning – Regulatory Support, NIPSCO;
- Kirstie Eyre, Compensation Manager, NCSC;
- John J. Spanos, President, Gannett Fleming Valuation and Rate Consultants, LLC;
- Vincent V. Rea, Managing Director, Regulatory Finance Associates, LLC;
- Jennifer A. Harding, Vice President of Tax, NCSC;[3]
- Melissa Bartos, Senior Vice President, Concentric Energy Advisors ("Concentric");
- John D. Taylor, Managing Partner, Atrium Economics, LLC ("Atrium"); and
- Candice Lash, Lead Regulatory Studies Analyst, NCSC.

As part of its requested relief, NIPSCO sought approval of an Alternative Regulatory Plan ("ARP") pursuant to Ind. Code § 8-1-2.5-6 to partially waive 170 IAC 4-1-16(f) and to approve Petitioner's proposed remote disconnection and reconnection process, and to the extent necessary to implement a low income program.

Petitions to Intervene were filed by United States Steel Corporation ("U.S. Steel"); NLMK Indiana, a division of NLMK USA ("NLMK"); NIPSCO Industrial Group ("Industrial Group");[4] Walmart Inc. ("Walmart"); Citizens Action Coalition of Indiana, Inc. ("CAC"); RV Industry

[1] On August 13, 2024, NIPSCO provided its notice of intent to file a rate case in accordance with the Commission's General Administrative Order 2013-5. Petitioner's Exhibit 1, Attachment 1-B.

[2] NIPSCO filed corrections or revisions to its case-in-chief on November 26, 2024, December 18, 2024, December 30, 2024, January 27, 2025, and February 6, 2025. NIPSCO also late-filed Attachments 1-C and 1-D (consisting of the Proofs of Legal Notice Publication and Customer Notice) to Mr. Parisi's testimony on January 20, 2025. NIPSCO originally filed the Verified Direct Testimony of Gregory Skinner, Vice President of IT Utilities Systems, NCSC that was not offered into evidence.

[3] NIPSCO initially filed the Verified Direct Testimony of Jonathan Bass, Director of Income Tax Planning & Controversy, NCSC.

[4] The companies that comprise the Industrial Group are BP Products North America, Inc., Cleveland-Cliffs Steel LLC, Linde, Marathon, and USG.

User's Group ("RV Group");[5] United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12775 and 13796 ("USW"); and Board of County Commissioners of LaPorte County, Indiana ("LaPorte County"). These petitions were granted without objection. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated as a party.

Pursuant to Ind. Code § 8-1-2-61(b), public field hearings were held in Valparaiso, Indiana on November 26, 2024; in Hammond, Indiana on December 5, 2024; and in Gary, Indiana on December 5, 2024. Members of the public presented testimony at each of these hearings.

On December 19, 2024, the OUCC and certain intervenors filed their respective cases-in-chief. For purposes of its case-in-chief, the OUCC prefiled written consumer comments and testimony and attachments from the following witnesses:[6]

- Michael D. Eckert, Chief Technical Advisor, OUCC Electric Division;
- Brian R. Latham, Utility Analyst, OUCC Electric Division;
- Kaleb G. Lantrip, Utility Analyst, OUCC Electric Division;
- Brittany L. Baker, Utility Analyst, OUCC Electric Division;
- Brian A. Wright, Utility Analyst II, OUCC Electric Division;
- Roopali Sanka, Utility Analyst, OUCC Electric Division;
- Gregory L. Krieger, Utility Analyst, OUCC Electric Division;
- Leja D. Courter, Chief Technical Advisor, OUCC;
- John W. Hanks, Utility Analyst, OUCC Electric Division;
- April M. Paronish, Assistant Director, OUCC Electric Division; and
- Michael W. Deupree, a consultant with Acadian Consulting Group.

The OUCC also included with its pre-filed evidence written consumer comments pertaining to the relief requested in NIPSCO's Petition as Public's Exhibit No. 13. On December 30, 2024, and pursuant to a docket entry issued the same day, the OUCC late-filed the testimony and attachments of Roxie McCullar, consultant with William Dunkel and Associates.

The Industrial Group prefiled testimony and attachments from James R. Dauphinais and Michael P. Gorman, both Managing Principals with Brubaker & Associates, Inc., and Brian C. Andrews, a Principle with Brubaker & Associates, Inc.[7]

NLMK prefiled testimony and attachments from Jared R. Robertson, Senior Consultant for Energy Strategies, LLC.

Walmart prefiled the testimony and attachments of Lisa V. Perry, Director, Utility Partnerships – Regulatory for Walmart.

[5] The companies that comprise the RV Group are: LCI Industries, Inc., Forest River, Inc., Patrick Industries, Inc., and Thor Industries.
[6] The OUCC filed corrections to its case-in-chief on January 15 and January 31, 2025.
[7] The Industrial Group filed corrections to its case-in-chief on February 7, 2025.

The CAC prefiled the testimony and attachments of Benjamin Inskeep, Program Director for the CAC.[8]

The RV Group prefiled the testimony and attachments of Jeffry Pollock, Energy Advisor and President of J. Pollock, Incorporated and Jonathan W. Burke, Chief Energy Consultant at Tactical Energy Group, Inc.

U.S. Steel prefiled the testimony of Jill A. Schuepbach, a Principal in the Energy Practice of NewGen Strategies and Solutions, LLC for U.S. Steel.

LaPorte County prefiled the testimony and attachments of Connie Gramarossa, Board President of LaPorte County; Melissa Whited, Vice President of Synapse Energy Economics; and Michael R. O'Connell, Principal Consultant for Midwest Energy Consulting LLC.

On January 16, 2025, the Industrial Group prefiled cross-answering testimony of James R. Dauphinais; the CAC prefiled cross-answering testimony of Benjamin Inskeep; the RV Group prefiled cross-answering testimony of Jeffry Pollock;[9] and NLMK prefiled cross-answering testimony of Jared R. Robertson. On January 17, 2024, U.S. Steel prefiled cross-answering testimony of Jill Schuepbach and on January 23, 2024, the OUCC prefiled the cross-answering testimony of Michael W. Deupree.[10]

NIPSCO prefiled rebuttal testimony, exhibits, and workpapers on January 16, 2025, for the following witnesses:

- Erin E. Whitehead;
- Richard D. Weatherford;
- Nick Bly;
- Orville Cocking;
- John J. Spanos;
- Vincent V. Rea;
- Jennifer A. Harding;
- John D. Taylor;
- Alan Felsenthal, Managing Director, PricewaterhouseCoopers LLP; and
- Karl E. Stanley, Vice President of Supply & Optimization for NiSource, Inc.

On February 7, 2025, a Stipulation and Settlement Agreement ("Settlement" or "Settlement Agreement") was filed by NIPSCO, the OUCC, the Industrial Group, NLMK, U.S. Steel, Walmart, and the RV Group (collectively the "Settling Parties").

On February 7, 2025, NIPSCO prefiled the settlement testimony, attachments, and workpapers of Ms. Whitehead, Mr. Weatherford, and Mr. Taylor in support of the Settlement

[8] The CAC late-filed Attachment BI-4 (consisting of the Field Hearing Transcripts) to Mr. Inskeep's testimony on February 3, 2025.
[9] The RV Group also updated its list of companies to remove Patrick Industries, Inc.
[10] The OUCC filed corrections to its cross-answering testimony on January 31, 2025.

Agreement. Also on February 7, 2025, the following witnesses of the OUCC and other Settling Parties filed additional evidence supporting the Settlement Agreement:

- Brian R. Latham;
- Michael P. Gorman;
- James R. Dauphinais;
- Lisa V. Perry; and
- Jill A. Schuepbach

On February 28, 2025, the CAC filed additional testimony of Mr. Inskeep opposing the Settlement Agreement.

On March 7, 2025, NIPSCO prefiled the settlement reply testimony of Ms. Whitehead and Mr. Taylor, the OUCC prefiled the settlement reply testimony of Mr. Deupree, U.S. Steel prefiled the settlement reply testimony of Ms. Schuepbach,[11] and the Industrial Group prefiled settlement reply testimony of Mr. Dauphinais. Also on March 7, 2025, the RV Group and Walmart filed their Joinder in Settlement Reply Testimony.

An evidentiary hearing was conducted in this Cause at 9:30 a.m. on March 25, 2025, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the evidentiary hearing, the Settlement Agreement and the direct, cross-answering, rebuttal, settlement, opposing settlement, and settlement reply testimony and exhibits of each party as well as certain stipulations in lieu of cross-examination were offered and admitted into the record without objection.

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

1. Notice and Jurisdiction. Legal and timely notice of the public hearings held in this Cause was given and published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a) and an "energy utility" as that term is defined in Ind. Code § 8-1-2.5-2. NIPSCO is subject to the Commission's jurisdiction for approval of its rates and charges for electric utility service under Ind. Code §§ 8-1-2-42 and -42.7. NIPSCO has also elected to become subject to Ind. Code § 8-1-2.5-6. NIPSCO caused to be published the filing of its Petition pursuant to Ind. Code §§ 8-1-2-61 and 8-1-2.5-6 and mailed notice to its customers as required by 170 IAC 4-1-18(C). The Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. Petitioner's Organization and Business. NIPSCO is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders retail electric utility service to more than 487,000 retail customers located in all or part of the following Indiana counties: Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren, and White. Additionally, NIPSCO is subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and is a member of Midcontinent Independent System Operator, Inc. ("MISO"), a regional transmission organization operated under FERC's authority

[11] U.S. Steel prefiled corrections to Ms. Schuepbach's testimony on March 17, 2025.

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

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

3. Existing Rates. The Commission approved NIPSCO's current electric basic rates and charges in its August 2, 2023 Order in Cause No. 45772 ("45772 Order"). The petition initiating Cause No. 45772 was filed with the Commission on September 19, 2022; therefore, in accordance with Ind. Code § 8-1-2-42(a), it has been more than 15 months since NIPSCO filed its most recent petition for an increase in basic rates and charges and the filing of NIPSCO's Petition in this Cause.

In the 45772 Order, the Commission approved a Stipulation and Settlement Agreement ("45772 Settlement") which included a Stipulation and Settlement Agreement between NIPSCO and its industrial customers on Rate 831/531[12] implementation (the "Rate 831/531 Modification Settlement").[13]

4. Test Year and Rate Base Cutoff. As authorized by Ind. Code § 8-1-2-42.7(d)(1), NIPSCO proposed a forward-looking test period using projected data, with the test year used for determining projected operating revenues, expenses, and net operating income being the 12-month period ending December 31, 2025 ("Forward Test Year"). NIPSCO is utilizing the test year end, December 31, 2025, as the general rate base cutoff date. The historical base period is the 12-month period ending December 31, 2023.

In its Petition, NIPSCO proposed a two-phase rate implementation, with potential interim phases, to reasonably reflect actual rate base, including the utility property that is used and useful at the time rates are placed into effect. Base rates would be implemented in two steps, with the first step following issuance of an Order in this Cause and based upon the actual rate base and capital structure using a general rate base cutoff of May 31, 2025 (Step 1). The second step would take place following the close of the test year, based upon actual rate base and capital structure as of December 31, 2025 (Step 2).

NIPSCO proposed up to two additional steps for two "major projects" (as that term is defined in 170 IAC 1-5-1(l)). The two major projects are the Fairbanks Solar Generating Facility ("Fairbanks") and the Gibson Solar Generating Facility ("Gibson"). Each project is expected to cost greater than 1% of NIPSCO's projected net original cost rate base. A certificate of public convenience and necessity ("CPCN") was issued for Fairbanks originally in Cause No. 45511 and

[12] Rate 831 is the tariff rate approved for NIPSCO's large industrial customers in Cause No. 45159, which was later updated to Rate 531 in Cause No. 45772 and is being updated in this case to Rate 631.

[13] The Rate 831/531 Modification Settlement was entered into on September 12, 2022 by and between NIPSCO, Cleveland-Cliffs Steel LLC, Linde, Inc., BP Products North America, Inc., Cargill, Inc., NLMK Indiana, Pratt Paper (IN), LLC, and US Steel.

revised in Cause No. 46028. A CPCN was issued for Gibson originally in Cause No. 45926 and revised in Cause No. 46032. Fairbanks is expected to be in service by the Phase 1 general rate base cutoff and Gibson to be in service by July 31, 2025. NIPSCO proposed additional steps for these two projects to the extent they are not in service by May 31, 2025 by adjusting rates to reflect return (using the capital structure as of May 31, 2025) and depreciation rates reflected in the underlying Order issuing the CPCN. To the extent the projects are not in service by May 31, 2025 but are in service by the time Phase 1 rates are implemented, NIPSCO proposed to include the interim step in the Phase 1 implementation. NIPSCO was granted a waiver of the monthly investment reporting requirement set forth in 170 IAC 1-5-5(5)(D) but was required to declare major projects used and useful in accordance with 170 IAC 1-5-5.

5. NIPSCO's Requested Relief. NIPSCO seeks approval of changes to its basic rates and charges for electric utility service and associated accounting relief to provide NIPSCO with the opportunity to recover its ongoing costs of providing electric utility service and earn a fair return on the fair value of its property.

6. Opposition, Rebuttal, and Cross-Answering. The OUCC and intervenors raised numerous challenges to NIPSCO's filing, including, but not limited to, challenging rate base, rate of return, operation and maintenance ("O&M") expenses, depreciation rates, cost of service allocation, and rate design. The extent to which these parties disagreed with each other is reflected in their cross-answering testimony. The extent to which NIPSCO disagreed or agreed with the OUCC and intervenors was addressed in NIPSCO's rebuttal evidence.

7. Settlement Agreement and Supporting Testimony. The Settling Parties' witnesses presented testimony in support of the Settlement Agreement. They discussed the terms of the Settlement Agreement and explained how the Settlement Agreement resolves all issues presented in the case in a fair and reasonable manner, including issues related to the revenue requirement, cost of service, rate design, and cost allocation. The terms of the Settlement Agreement specifically state that it is a settlement of all issues among the Settling Parties in this Cause. In addition to the Settling Parties, LaPorte County and the USW agreed not to oppose the Settlement.

The Settling Parties' witnesses conveyed that the Settlement Agreement is a product of a diligent effort by all the Settling Parties to reach a comprehensive result. The complexity of the issues and the diverse interests of the Settling Parties dictated the need for compromise on the part of each party involved, and the Settlement Agreement, taken as a total package, reflects a delicate balance that the Settling Parties agree reasonably accommodates their interests.

Ms. Whitehead testified the Settlement is comprehensive in scope and proposes to fairly resolve all issues in dispute. She testified that it provides NIPSCO with an increase in rate revenue sufficient to enable it to meet its revenue requirement, including providing an opportunity to earn an adequate return on the investments made to serve its customers. She stated that after much compromise, NIPSCO agreed to a $111,616,865, or 30.28%, reduction from the increase requested in its case-in-chief.

According to Mr. Latham, if approved, the Settlement will provide certainty regarding critical issues that would have otherwise remained contested and reasonably resolves them. The

resolved issues include revenue requirements, authorized return, a proposed low income opt-out program, a proposed new multi-family rate class, and the allocation of NIPSCO's revenue requirement among its various rate classes. He explained that the Settlement is the product of intense negotiations, with each party making informed decisions and/or compromises regarding challenging issues and assessing the litigation risks. He said that while the Settlement represents a balancing of interests, the OUCC, as the statutory representative of NIPSCO's ratepayers, concluded the Settlement is a fair resolution, is within the range of outcomes supported by the case's evidence, and should be approved. He noted considerable effort was expended over multiple weeks in balancing the interests of customers and NIPSCO while engaging in arm's length negotiations.

Ms. Schuepbach testified that the Settlement terms represent an equitable compromise among the Settling Parties in this proceeding. Further, she explained that the terms agreed upon in the Settlement will keep NIPSCO profitable and will allow U.S. Steel to remain a customer on the NIPSCO system. She said that other customer classes benefit as well because of reductions in the overall system revenue requirement and the settlement class revenue allocators. She said the Settling Parties worked hard to agree on an outcome that represented the best possible result for each customer class and NIPSCO.

Ms. Perry asserted that the Settlement represents significant compromise among parties with diverse interests based on the evidence presented on the complex issues in this case. She maintained that the Settlement will produce an opportunity for NIPSCO to earn sufficient revenues to provide adequate service to its customers at a fair return while preserving customers' interests in safe and reliable service and reasonable rates.

Mr. Gorman testified the Settlement was the product of arm's length negotiations conducted in good faith by a range of parties with diverse interests represented by competent counsel, and subsequent to the presentation of their positions in evidentiary filings and discovery. Noting the case raised a number of issues on a variety of subjects, he said the Settling Parties were nevertheless able to achieve consensus on the terms of a comprehensive Settlement. In Mr. Gorman's opinion, the Settlement, taken as a total package, is a reasonable resolution that appropriately balances the various interests of the Settling Parties in a manner consistent with sound ratemaking principles.

Mr. Dauphinais testified that, as a total package, the Settlement resolves all of the issues in this complex proceeding on terms that are supported by the record, falls within the range of litigation positions put forward by the parties, and reflects reasonable compromises on the disputed issues. He expressed his belief that the cost of service and rate design terms operate in conjunction with the revenue terms to produce rates that are just and reasonable for all classes. He said each term is integral to the overall reasonableness of the Settlement.

A. <u>Settlement Overview</u>. Ms. Whitehead explained that the specific objectives addressed in the Settlement are to establish a level of basic rates and charges for NIPSCO which are calculated to provide the opportunity to earn a fair return on the fair value of its plant and equipment.

Ms. Whitehead noted the Settling Parties have agreed that NIPSCO's base rates will be designed to produce gross revenue at proposed rates of $2,086,642,669, resulting in a proposed authorized net operating income of $651,868,680. Ms. Whitehead also supported the Settlement Agreement's stipulated return on equity ("ROE") of 9.75%. Mr. Weatherford explained that under the Settlement Agreement, the total increase in base rates results in a revenue increase from current base rates of $257,043,752. The stipulated revenue requirement under the Settlement results in a reduction of $111,616,865 from the amount NIPSCO originally requested in its case-in-chief. Mr. Weatherford presented all the settlement adjustments in his settlement testimony.

Mr. Latham explained that under the Settlement, NIPSCO's originally requested revenue increase is significantly reduced by agreement upon a lower revenue requirement amount and through rate design, thereby furthering affordability. Additionally, NIPSCO's residential customer charge remains unchanged at $14 in response to the many ratepayers who voiced opposition to NIPSCO's proposed increase in this charge.

As shown in Petitioner's Exhibit 2-S, Attachment 2-S-A, NIPSCO estimates that residential bills for the average customer consuming 672 kilowatts per hour ("kWh") would increase approximately 16.75% following Step 2 rate implementation, including anticipated changes in NIPSCO trackers. Ms. Whitehead testified that under NIPSCO's case-in-chief, residential customers would have received a 22.01% increase following Step 2 rate implementation, based on an average residential customer usage of 729 kWh. She noted that combining the multi-family rate (proposed Rate 615) into Rate 611 results in lower average overall residential customer consumption, which makes comparing these average residential bill impacts challenging.

B. <u>Revenue Requirement</u>. The Settlement Agreement provides that NIPSCO's base rates will be designed to produce $2,086,642,669 prior to application of surviving Riders. The increase in base rates results in an increase from current base rates of $257,043,752. The agreed upon revenue requirement reflects the depreciation study and accrual rates and amortization provided in the Settlement Agreement. The stipulated revenue requirement is calculated to produce authorized net operating income of $651,868,680. Mr. Weatherford described the Step 2 revenue requirement and sponsored the supporting schedules.

Mr. Gorman testified that the agreed upon revenue requirement reflects total reductions equal to just under 58% of the total value of the adjustments proposed by the Industrial Group.

C. <u>Original Cost Rate Base, Capital Structure, and Rate of Return</u>. The Settlement provides that the weighted average cost of capital times NIPSCO's original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settlement provides that NIPSCO should be authorized a fair rate of return of 7.14%. The Settlement provides for a projected net original cost rate base at Step 2 of $9,129,813,441. The Settlement also provides for NIPSCO's forecasted capital structure, including its Prepaid Pension Asset and Post-Retirement Liability at zero cost as reflected in NIPSCO's direct and rebuttal testimony, and a stipulated ROE of 9.75%. The Settlement provides for the following forecasted capital structure at Step 2:

	Total Company Capitalization	Cost %	Weighted Average Cost %
Common Equity	$7,718,129,223	9.75%	5.17%
Long-Term Debt	$5,468,979,284	5.20%	1.95%
Customer Deposits	$59,885,295	5.63%	0.02%
Deferred Income Taxes	$1,691,723,532	0.00%	0.00%
Post-Retirement Liability	$(7,491,885)	0.00%	0.00%
Prepaid Pension Asset	$(372,308,313)	0.00%	0.00%
Post-1970 Investment Tax Credit	$174,612	7.87%	0.00%
Totals	**$14,559,091,748**		**7.14%**

In its case-in-chief, NIPSCO proposed a 10.6% ROE and several intervenors, including the OUCC and the Industrial Group, advocated for a considerably lower ROE. The testimony in support of the Settlement Agreement explained that as a result of the negotiations, a compromise was reached between the NIPSCO and intervenor ROE recommendations, resulting in a 9.75% ROE in the Settlement. Ms. Whitehead explained that if NIPSCO's ROE is set too low, it could lead to financial insecurity that would place increased risk on NIPSCO's ability to attract capital, which could also challenge NIPSCO's ability to obtain the capital necessary to continue to provide safe, reliable, and affordable service to its electric customers.

Ms. Whitehead explained that although settlement agreements are not precedential, the Settlement's agreed ROE of 9.75% is slightly lower than or equal to: (1) the negotiated NIPSCO ROE of 9.80% reflected in the settlement approved by the Commission in its 45772 Order; (2) the negotiated AES Indiana ROE of 9.90% approved by the Commission on April 17, 2024 in Cause No. 45911; (3) the negotiated Indiana Michigan Power Company ROE of 9.85% approved by the Commission on May 8, 2024 in Cause No. 45933; (4) the litigated Duke Energy Indiana, LLC ("Duke") ROE of 9.75% approved by the Commission on January 29, 2025 in Cause No. 46038; and (5) the negotiated CenterPoint Energy Indiana South ("CEI South") ROE of 9.8% approved by the Commission on February 3, 2025 in Cause No. 45990. She said for all these reasons, the Settlement Agreement represents a reasonable outcome related to ROE in this proceeding. The Settlement Agreement provides, at Section C.4., that the Agreement "has accounted for the overall level of risk presented to NIPSCO by the Agreement."

Mr. Latham testified the agreed original cost rate base of $9,129,813,441 is lower than the OUCC's recommended rate base of $9,229,256,490 as of December 31, 2025, which reflects the OUCC's recommended $556,951 inventory adjustment NIPSCO accepted in its rebuttal testimony. He explained that the OUCC's case-in-chief recommended a 9.00% cost of equity and that, in the context of the overall settlement, the OUCC considers the agreed 9.75% cost of equity to be a reasonable result. It is within the range of cost of equity evidence presented to the Commission and is a favorable decrease from NIPSCO's currently authorized level, particularly when combined with other compromises made in the Settlement.

Ms. Perry testified she provided numerous concerns with NIPSCO's proposed 10.6% ROE and presented evidence regarding Walmart's perspective on a reasonable authorized return. While the 9.75% ROE set forth in the Settlement may not be as low as Walmart would have advocated

for in litigation, for the purposes of settlement, Walmart believes that a 9.75% ROE provides NIPSCO the opportunity to earn a fair return while still protecting customers' expectations of safe and reliable service at just and reasonable rates.

Mr. Gorman testified that the Industrial Group recommended that NIPSCO's current cost of equity be set in the range of 9.10% to 9.70%, with a point estimate of 9.40%. His analysis was based upon observable market evidence, an assessment of the risk premium associated with market securities, and a general assessment of the market risk associated with investment in regulated utilities. He testified that a further reduction was appropriate to reflect the lower financial risk NIPSCO faces due to its equity rich capital structure to arrive at his recommended ROE of 9.15%. He also conducted an analysis which determined that his recommended ROE would continue to provide NIPSCO with access to adequate capital on reasonable terms. He testified that although 9.75% is higher than his recommended ROE, and slightly outside his recommended range, it is well below the 10.60% to 11.10% range proposed by NIPSCO. Further, the agreed upon ROE is slightly below NIPSCO's current authorized ROE of 9.80%, and below the midpoint between his recommended 9.15% and NIPSCO's requested 10.60% ROE. He stated that, given the totality of the evidence in this case, he considers the 9.75% ROE to be reasonable.

D. Depreciation and Amortization. The Settlement Agreement decreases depreciation expense by $12,270,000 from NIPSCO's case-in-chief filing, which is comprised of a $10,000,000 reduction as a result of reducing decommissioning costs and adjusting originally proposed service lives or net salvage components associated with certain depreciation accrual rates and a $2,270,000 reduction as a result of the $100,000,000 reduction to NIPSCO's case-in-chief projected Transmission & Distribution Rate Base. The proposed depreciation accrual rates by FERC Account that result from these changes are included in Joint Exhibit B to the Settlement.

The Settlement also decreases NIPSCO's amortization expense by $5,556,445 achieved by changing the amortization periods for the transmission, distribution, and storage system improvement charge ("TDSIC") and Electric Rate Case Expense regulatory asset balances from two to four years. NIPSCO will make a compliance filing at the conclusion of all amortization periods to remove the amortization from the revenue requirement, and rates will be adjusted accordingly. Mr. Weatherford explained the $5,556,445 deduction is comprised of a decrease of $4,909,882 for the extended amortization of the TDSIC regulatory asset to now amortize over an additional two-year period through August 2029, which deviates from NIPSCO's originally proposed amortization period of two years, and a decrease of $646,563 to reflect Electric Rate Case Expense of $2,586,251 to amortize over a period of four years. This reflects an increase of two years in the period over which the total will be amortized.

Mr. Latham testified that the Settlement Agreement's $12,270,000 depreciation reduction equates closely to the OUCC's recommended $12,557,795 reduction to NIPSCO's proposed depreciation. He also testified that the agreed $5,556,445 reduction to amortization expense is due to extending the amortization periods for the TDSIC and Electric Rate Case Expense regulatory asset balances from two to four years. He said extending the amortization period for these assets reduces the annual financial burden on ratepayers. NIPSCO agreed to also make a compliance filing at the conclusion of all amortization periods to remove the amortization from the revenue requirement and adjust rates accordingly. Mr. Latham explained that NIPSCO's agreement to adjust rates will lower rates as the amortization periods end.

Mr. Gorman testified that the Industrial Group proposed a significant reduction to NIPSCO's depreciation expense of $46.36 million, based, in large part, on the Industrial Group's concerns related to proposed increases in decommissioning costs for NIPSCO's steam production assets, as well as reductions in net salvage value. Mr. Gorman testified that in his view, the $10 million assigned by the Settlement to reduce decommissioning costs and adjust net salvage value is a reasonable result within the range of reasonably expected outcomes.

E. Pro Forma Net Operating Income at Present Rates. The Settlement Agreement resolved issues raised by the parties concerning pro forma net operating income at present rates for fuel costs and O&M expenses. The Settling Parties agreed that the base cost of fuel proposed in NIPSCO's case-in-chief will be reduced by $8,970,840 and agreed to a $20 million reduction to total O&M. This reduction is a compromise to resolve numerous disputed issues, including NIPSCO labor vacancies (generation and non-generation related), NCSC labor vacancies, vegetation management expense, and costs incurred to execute NIPSCO's rate case.

Mr. Latham testified that the Settling Parties agreed NIPSCO's pro forma O&M expenses should be decreased by $20 million. He said this reduction is a general compromise to resolve numerous disputed O&M issues including labor vacancies, vegetation management expenses, and rate case expenses. He explained the OUCC advocated that ratepayers should not be financially responsible for all of NIPSCO's rate case expenses and a reduction was incorporated into the Settlement O&M expense. He stated the Settling Parties also agreed to a $8,970,840 reduction in fuel costs consistent with the OUCC's litigation position.

Mr. Gorman testified that the total reduction in NIPSCO's O&M expense of $20 million resolves a number of disputes between the parties, including NIPSCO's proposed increases in vegetation management program costs, unfilled labor positions, corporate shared services costs, and challenges to the recovery of litigation related expenses. In his opinion, the total adjustment reflects a reasonable resolution to the areas of dispute and good faith efforts to reach compromise in the face of both sides' litigation risk.

F. Low Income Program. The Settlement provides for the approval of NIPSCO's proposed bill assistance program (Rider 697 – Universal Service Program Rider) with the following changes: (1) in recognition of concerns the OUCC expressed, NIPSCO agrees to modify the bill assistance program from an opt-out program as proposed in NIPSCO's rebuttal to a voluntary, opt-in program; and (2) in recognition of concerns expressed by the Settling Parties, NIPSCO will make an annual, below the line (i.e., not to be recovered through rates) shareholder contribution of $1,500,000.

Mr. Latham testified the bill assistance in the Settlement is a ratepayer favorable outcome as NIPSCO will contribute a significantly greater amount of shareholder funding to the program than NIPSCO proposed in its case-in-chief ($400,000). He also testified that ratepayers will have the opportunity to opt into the program to help those needing assistance and that a benefit of opt-in over opt-out is that an opt-in plan does not rely on involuntary ratepayer contributions, but instead enables ratepayers to choose to participate in NIPSCO's assistance program.

G. Other Customer Issues. The Settlement includes the following additional provisions to address affordability: (1) the Settling Parties agreed to a reduction of NIPSCO's

customer deposit from $50 to $0 for all gas and electric customers who receive bill assistance through the Low Income Home Energy Assistance Program ("LIHEAP"); (2) for electric customers who are disconnected for non-payment of charges, NIPSCO agreed to waive its $90 electric reconnection charge (at the meter during normal business hours) set out in Section 15.1.1 of its General Rules and Regulations no later than with the implementation of Step 2 rates; (3) NIPSCO agreed to delay disconnection for non-payment of electric service if temperatures are below 20 degrees or above 90 degrees on the day of disconnection or are forecasted to be below 20 degrees or above 90 degrees the following two days; and (4) NIPSCO committed to a stakeholder process within six months of the date of a final order in this Cause with the intent of incorporating a public-facing electric vehicle ("EV") rate to facilitate charging at customer-owned locations in NIPSCO's next electric base rate case.

Mr. Latham testified the elimination of the customer deposit will benefit NIPSCO's gas and electric LIHEAP-eligible customers by making additional funds available to meet their day-to-day expenses rather than their cash being required for this deposit. He testified that waiving NIPSCO's $90 reconnection charge no later than the implementation of Step 2 rates will enable further potential ratepayer savings. Additionally, delaying disconnection for non-payment of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or are forecasted to be below 20 degrees or above 90 degrees the following two days is beneficial during periods of extreme weather for ratepayers who may struggle to pay electric bills. Regarding the stakeholder process for a public-facing EV rate, Mr. Latham stated that, as the need for EV chargers grows, NIPSCO's commitment to a stakeholder process that incorporates input from all affected parties, including the public, should facilitate the availability of this additional electric infrastructure.

Ms. Perry stated that in her direct testimony, she recommended that NIPSCO offer a rate structure for business customers who are interested in owning and operating public EV charging equipment, specifically direct current fast chargers, to ensure that such chargers owned by a third-party are able to remain competitive. She said this would foster a robust marketplace for EV charging equipment, encouraging the expansion of a comprehensive EV charging network across Petitioner's service territory. She testified the stakeholder process and intent to incorporate a public facing EV rate in NIPSCO's next rate case adopts her recommendation and Walmart commends NIPSCO for being willing to take this necessary step to further the advancement of competitive EV development to the benefit of its service territory and hopes to see similar developments throughout Indiana.

H. <u>Phased Rate Implementation</u>. The Settlement provides that the rate changes will be implemented on a services rendered basis after NIPSCO's new tariffs have been approved by the Commission's Energy Division. Implementation of the agreed rate increase would occur in multiple steps, as follows:

Step 1 rates shall be implemented on a services rendered basis as soon as possible following the issuance of an order and will be based on actual net plant certified to have been completed and placed in service no later than May 31, 2025, except for the Fairbanks and Gibson projects. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of May 31, 2025. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and

current capital structure as of May 31, 2025 and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of May 31, 2025. NIPSCO will provide all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of May 31, 2025, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

Step 2 rates shall be implemented on a services rendered basis as soon as possible after the end of the Forward Test Year and will be based on actual net plant certified to have been completed and placed in service no later than December 31, 2025. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2025. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2025 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2025. NIPSCO will provide all parties with its certification. The Settling Parties, and other interested parties to this proceeding, will have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

In the event Fairbanks and/or Gibson are not in service by the general rate base cutoff for Step 1 (May 31, 2025) but come into service on or before the general rate base cutoff for Step 2 (December 31, 2025), the Settling Parties agree to up to two additional steps to include these projects in rates earlier than Step 2 (end of the Forward Test Year). The compliance filing(s) for the additional step(s) will be based on the addition to rate base and associated depreciation expense for Fairbanks or Gibson (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification that the asset is in service, with a copy to all parties. The rates would take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in Step 1 rates calculated as provided in this paragraph.

Mr. Latham testified that, as advocated by the OUCC, the Settling Parties agreed the rate changes will be implemented on a services-rendered basis after NIPSCO's new tariff has been approved by the Commission's Energy Division. This helps to ensure the new rates are not applied to electric service rendered before their approval. Step 1 rates will be implemented on a services-

rendered basis as soon as possible following the issuance of an order in this Cause and approval of NIPSCO's new tariffs.

I. Cost of Service and Rate Design. In the Settlement, the Settling Parties acknowledge that, as presented in NIPSCO's case-in-chief and rebuttal, certain rate classes are being subsidized by several other rate classes. The Settlement Agreement proposes to mitigate a portion of the on-going subsidy concerns raised by multiple parties in an effort to balance the goal of subsidy reduction with a policy of gradualism. Consistent with the mitigation approach approved in the 45772 Order, the Settlement revenue requirement reduction (i.e., the settled annual revenue requirement below NIPSCO's as-filed case in chief) will be apportioned as follows: (1) set revenues for Rate 631 at cost of service based on 162.061 megawatts ("MW") of allocated Tier 1 demand; (2) no revenue change to Rate 642 and Rate 643; (3) credit $575,000 of the Settlement revenue requirement decrease first to each Rate 623 and Rate 626; (4) allocate 25% of the remaining Settlement revenue requirement decrease to the subsidizing classes in proportion to their excess revenues (25% portion); and (5) allocate the remaining amount on an across-the-board basis in proportion to NIPSCO's case-in-chief proposed revenues (the "25% portion"). Because Rate 631 is being brought to parity assuming 162.061 MW of allocated demand, it will not receive either a reduction relating to the 25% portion or a reduction related to the 75% portion, nor will Rate 642 and Rate 643 as there is no change in their revenues. Rate 611 will participate in the across-the-board reduction (the "75% portion"). The provisions of this paragraph are to be implemented in the cost of service and rates included with NIPSCO's testimony supporting the Settlement Agreement.

In Petitioner's Exhibit 16-S, Mr. Taylor presented the Settlement revenue apportionment, and the Settlement proposed class rate increases in Attachment 16-S-A. Table 1 in Mr. Taylor's settlement testimony shows the mitigation of interclass subsidies from the case-in-chief proposal to the Settlement. He presented Attachment 16-S-B which shows detailed calculations for each rate component of each rate schedule, as well as how the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, Attachment 16-S-B shows the transition of revenues at current rates and existing 500 series rate classes to the proposed revenues at the 600 series rate classes. Mr. Taylor sponsored Attachment 16-S-C, showing the typical bill impacts for residential customers. Mr. Taylor also sponsored Attachment 16-S-D as a revised version, consistent with the Settlement, of Attachment 16-H to Petitioner's Exhibit 16, providing the updated tracker allocators that result from the Settlement changes to cost of service and revenue mitigation.

The Settlement Agreement provides that, in light of issues raised by the OUCC, the Industrial Group, U.S. Steel, and the CAC, NIPSCO will study its cost of service production, transmission, and distribution classification and allocation ("Allocation Study") before filing its next general electric rate case. This will include the study of the classification and allocation of production, transmission, and distribution customer, demand, and energy related costs both in base rates as well as in the fuel adjustment clause ("FAC") and resource adequacy ("RA") trackers. In its next general rate case, NIPSCO will file testimony addressing the results of the Allocation Study and supporting its decision regarding whether to make changes to the classification and allocation of production, transmission, and distribution costs.

The 45772 Settlement contemplated future reductions in Rate 531 Tier 1 contract demand and called for progressively narrowing the disparity between the Rate 531 allocated Tier 1 demand and the actual Tier 1 contract demands of customers in that class to bring that rate to parity with the cost to serve. The Settling Parties in this Cause agreed that the provisions of the 831/531 Modification Settlement and Section B.7.(e) through (g) of the 45772 Settlement continue to apply. The Settling Parties further agreed that the method for future reduction in Rate 631 Tier 1 allocated and contract demand provided for in the 831/531 Modification Settlement will be accomplished through the approach recommended by Mr. Dauphinais, with the exclusion of costs associated with Sugar Creek Generating Station, as recommended by Ms. Schuepbach. Using this approach, and reflecting the revenue adjustments under the Settlement, the allocated Rate 631 Tier 1 demand shall be 162.061 MW.

The Settling Parties agreed to Mr. Dauphinais's recommendation of proportional reductions to Rate 631 Tier 1 contract demand to progressively narrow the disparity between Rate 631 allocated demand and class contract demand to move the rate toward the actual cost of service. The minimum contract demand assumed for purposes of the Settlement is 153.692 MW. The Rate 631 charges (transmission, energy, and demand) will be based upon the 153.692 MW of assumed contract demand, which is expected to be consistent with executed Rate 631 contracts. The Settling Parties agree that further reductions to Rate 631 Tier 1 cost allocations in future rate proceedings should continue to follow the methodology set forth in Paragraph 7(f) of the 45772 Settlement employing the computational methodology utilized in the Settlement.

The Settlement also addresses a number of rate design issues unrelated to Rate 631. The Settlement provides that the revenue requirement decrease allocated to Rate 626 will be applied 50% to Rate 626's demand charge and 50% to its energy charge. The Settlement adopts the customer charges proposed by NIPSCO, except NIPSCO's existing monthly charge of $14 shall remain for Rate 611.

Mr. Taylor testified the Settlement allocated cost of service study ("ACOSS") structure and methodologies remain consistent with those described in his direct and rebuttal testimonies. The changes to the revenue requirement related to legacy coal generation were reflected in an update to the Rate 631 allocated demand in the Settlement ACOSS and the resulting Rate 631 cost of service is the basis of the revenue increase for that customer class. The Settlement ACOSS was further used to inform revenue apportionment to NIPSCO's other remaining customer classes. Mr. Taylor testified that while the ACOSS supports a higher residential customer charge, the Settling Parties agreed that the customer charge for Rate 611 will remain at $14 per month.

Mr. Latham testified the Settling Parties spent considerable time negotiating the revenue allocation among NIPSCO's rate classes. He said that because the OUCC represents all customer classes, the OUCC works to help ensure cost increases are fairly distributed across rate classes, while also being mindful of the importance of applying the principle of gradualism. The Settling Parties agreed to the customer charge increases NIPSCO proposed in its case-in-chief, with one exception. As recommended in the OUCC's direct testimony, NIPSCO's monthly customer charge for residential customers (Rate 611) will remain at $14. He said maintaining this charge is beneficial because ratepayer actions to mitigate the volumetric component of their bills may have a greater effect on the overall bill when the fixed charge is lower than the amount NIPSCO proposed in its case-in-chief.

Ms. Schuepbach testified the revenue requirement by customer class is based on the use of a four coincident peak ("4CP") allocation factor for production demand costs. Although her recommendation for the allocation of transmission costs by voltage was not addressed in this case, NIPSCO agreed to conduct an Allocation Study before filing its next general electric rate case. She said NIPSCO will either propose new methods for the classification and allocation or file testimony with the results of its analysis demonstrating why its current approach is still appropriate. She expects the Allocation Study to subfunctionalize transmission costs by voltage and then allocate the costs to each customer class based on the voltage at which they receive service for all rate base and revenue requirement components. She also expects NIPSCO to provide the results of the subfunctionalization analysis, describe how it affects the cost allocation to each rate class and for NIPSCO's Riders. She expects the allocation of transmission costs to Rate 631 to decrease as the majority of Rate 631 customers do not take power at, or use, the 69 kilovolt system.

Ms. Schuepbach testified the Rate 631 Tier 1 load and cost allocation in the Settlement Agreement is easy to understand, easy to duplicate, and defendable based on the language in the 45772 Settlement. She stated that when NIPSCO files its next general rate case, she expects to see the Rate 631 Tier 1 load and cost allocation calculation include only legacy coal assets, no trackable fuel, and be based on actual data for the coal plants. She expects that, as the coal legacy revenue requirement decreases, so will the allocated demand costs to Rate 631, and Rate 631 will reach 70 MW by 2035 when the coal legacy assets are fully depreciated and amortized.

Ms. Schuepbach testified the Settling Parties agreed to mitigate a portion of the settled revenue requirement increase to be consistent with a policy of gradualism. She said this mitigation is consistent with the 45772 Settlement, in that the differential continues to narrow between actual class capacity subscriptions and the allocated class capacity level. Rate 631 is held at parity based on a set total class demand level, as it was in the prior rate cases. She explained that absent Rate 631, there were and are valid concerns that industrial customers could shift their production to locations outside of NIPSCO and Indiana. She said that the Settlement revenue requirement allocated to each customer class was a product of negotiations that represented a reasonable compromise among the Settling Parties, considering very different views on the proper cost of service allocation methodologies. She opined that, in recognition that one allocation method compared to another dramatically shifted costs among rate classes, the Settlement Agreement represents a reasonable balance among the different perspectives that yields results that do not unduly harm one rate class over another and does not endorse one allocation method over another. She stated that with respect to U.S. Steel, the resulting rate increases to Class 631 of 10.32% represent an improvement compared to NIPSCO's original revenue proposal.

Ms. Schuepbach stated that for settlement purposes, the overall class rate increases are reasonable. The demand charge is significantly higher than most utility demand charges, but this is partially due to the difference between the demand costs allocated to Rate 631 and the actual contracted demand for the Rate 631 customers. She said if the demand costs of $65,921,733 are allocated to Rate 631 based on 162.1 MW of demand, the average rate is $33.90 per kW. However, the actual contract or billing demand for the class is 153.7 MW, resulting in a rate of $35.74 per kW, which is 5.4% higher. She said this disconnect between the allocated demand and the contract demand puts additional upward pressure on the demand charge.

Ms. Perry stated Walmart initially recommended that any reduction in revenue requirement from NIPSCO's originally requested amount be allocated by applying 50% of the overall revenue reduction to those rate classes who are paying in excess to their cost-based levels, except that in no event should a subsidizing rate class be moved to a subsidized position. The remaining 50% of the overall revenue reduction should be evenly applied to mitigate the proposed increases for all rate classes on an equal percentage basis. She testified that, while not adopting her proposal specifically, the revenue allocation set forth in the Settlement Agreement essentially adopts her proposal in concept. She stated that providing for a subsidy reduction by using 25% of the overall reduction in annual revenue (as opposed to Walmart's recommended 50%), combined with the additional marginal credit to Rate 626, is a reasonable compromise that benefits all classes while moving no class from a subsidized position to a subsidizing position or vice versa. However, she stated Walmart continues to maintain that greater movement to rectify subsidies is necessary.

Ms. Perry noted Walmart's initial concern that the structure of Rate 626 did not reflect appropriate intra-class cost causation by recovering demand-related costs through the energy component of the rate. Thus, she recommended that if a lower revenue requirement than that proposed by NIPSCO was approved, then the reduction to Rate 626's revenue requirement should be used to reduce the energy charge until the allocations match NIPSCO's cost of service study. She testified the Settlement Agreement adopts a compromise position that results in reasonable movement towards a cost-based rate design structure for Rate 626 that is also revenue neutral to all other rate classes.

Mr. Dauphinais stated the cost of service study presented in this case by NIPSCO was supported by expert testimony and was further supported by several parties including the Industrial Group. He noted its consistency with the cost of service methodology previously approved by the Commission and said the subsidy reduction provision is essentially identical to the corresponding provision in the 45772 Settlement. Several parties, including the Industrial Group, proposed greater reductions to inter-class subsidies, and other parties proposed less. Mr. Dauphinais testified the Settlement strikes a reasonable balance between the respective positions taken by the parties. The Settlement calls for NIPSCO to conduct an Allocation Study and to report on that study in its next rate case filing. He said it is always appropriate for a utility to review and assess reasonable approaches to analyzing cost of service in light of current circumstances and this provision properly leaves the decision to NIPSCO as to whether or not to propose any changes in its next rate case.

Mr. Dauphinais testified that under the 45772 Settlement, which includes the Rate 831/531 Modification Settlement, there will be progressive reductions to both the differential between imputed class demand used for allocation purposes and actual contract demand, as well as contracted Tier 1 demand in excess of the tariff minimum under Rate 631 and successor rates. In both respects, the reductions are calibrated to decreases in costs related to legacy coal plants as recovered in base rates. While this mechanism was approved by the Commission in NIPSCO's last rate case, he said there were some differences among the parties regarding the appropriate way to implement the mechanism. In the Settlement Agreement, the parties agreed to adopt the methodology proposed in his direct testimony, as well as a recommendation proposed in Ms. Schuepbach's testimony. He said the agreed methodology provides clarity regarding the implementation of the Rate 631 Tier 1 adjustment mechanism approved in the 45772 Order, is

consistent with the terms of that previously approved agreement, and provides appropriate guidance and framework for future implementation in successive rate proceedings.

J. Multi-Family Rate. In the Settlement, the Settling Parties agree NIPSCO's proposed multi-family rate, Rate 615, shall not be implemented. NIPSCO will collect additional data on residential customer housing types to better identify multi-family customers and further analyze cost differentials between single- and multi-family residential customers and may consider requesting a new multi-family rate for qualifying residential customers in its next rate case. Once additional analysis is complete, NIPSCO will meet with the CAC, the OUCC, and any other interested stakeholders prior to filing its next base rate case to discuss a potential multi-family rate and will provide interested stakeholders with the results of its analysis.

Mr. Taylor testified that both the OUCC and the CAC addressed proposed Rate 615, expressing concerns about the robustness of Petitioner's analysis that was used to establish the rate. Both parties were critical about NIPSCO's ability to identify the potential multi-family customers, the associated load research information used to quantify those customers' demand requirements, and the planning and engineering information used to determine the cost of service differences between single family and multi-family premises. Ultimately, the CAC recommended the adoption of Rate 615 whereas the OUCC recommended denial pending more thorough study. In recognition of these concerns, the Settling Parties agreed to forgo the separation of multi-family customers from Rate 611 at this time.

Mr. Latham testified NIPSCO will continue to collect data on residential customer housing types to better identify its multi-family customers and analyze the cost differentials between NIPSCO's single- and multi-family residential customers. He said this additional insight into NIPSCO's customer housing types and a more robust sample than NIPSCO used in this proceeding should facilitate a better informed analysis when considering a separate multi-family rate and its prospective impact upon NIPSCO's rate classes.

K. Data Center Sub-docket. Certain parties requested the creation of a sub-docket for purposes of developing a standard tariff offering and addressing other pertinent issues related to new large load customers that may locate in NIPSCO's electric service territory. The Settlement recognizes that since the filing of NIPSCO's case-in-chief and the OUCC's and intervenors' cases-in-chief, a filing was made related to NIPSCO's proposed overall strategy to serve large load customers, in which it was acknowledged that NIPSCO has not entered into any special contract or equivalent agreement for energy services for a large load customer. NIPSCO expressed its intention that any large load customer that may enter into a contract for electric service will commit to pay the direct, incremental costs associated with serving their load and some portion of the costs of NIPSCO's existing electric system. Accordingly, NIPSCO agreed that to the extent it enters into such contract(s), NIPSCO commits to timely file a proposal with the Commission to pass back to NIPSCO's current electric customers the revenues collected that are related to payment for recovery of some portion of the costs of NIPSCO's existing electric system paid by the large load customer(s). Under the Settlement, no party waives or is otherwise limited in making any argument in pending Cause No. 46183 or related dockets surrounding large load customers, but NIPSCO is precluded from requesting that any portion of the above identified revenues not be passed to NIPSCO's then current electric customers.

Mr. Latham stated that NIPSCO intends for any large load customer that may enter into a contract for electric service to commit to pay the direct, incremental costs associated with serving its load and some portion of NIPSCO's existing electric system costs. To the extent NIPSCO enters into such contracts, he stated NIPSCO committed to timely filing a proposal to pass back to its current electric customers the revenues collected related to payments for recovery of the portion of the costs of NIPSCO's existing electric system paid by large load customers. He explained it is beneficial to NIPSCO's pre-existing ratepayers if large load customers fund a portion of system costs because this funding would reduce system costs for NIPSCO's other ratepayers and be realized when NIPSCO receives an order on its "pass-back" filing.

Ms. Schuepbach testified that, although NIPSCO has stated existing customers will not be harmed or saddled with any incremental costs associated with large load customers, she hopes her concerns regarding the transparency of the transactions between NIPSCO and the large load customers and unintended effects on existing rate payers will be addressed in Cause No. 46183.

L. Other Relief Requested by NIPSCO. Section B.14. of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement but expressly supported by NIPSCO's testimony should be approved as NIPSCO proposed or, if modified in NIPSCO's rebuttal, consistent with such modification, without waiving the right to challenge such resolution prospectively.

M. Typical Bill Comparison. Attachment 2-S-A of Petitioner's Exhibit 2-S shows the estimated impact on an average residential customer's monthly electric bill and how that compares to the estimated bill impact on customers in NIPSCO's case-in-chief. Ms. Whitehead said that NIPSCO estimates that residential bills for the average customer consuming 672 kWh would increase approximately 16.75% following Step 2 rate implementation, inclusive of anticipated changes in trackers. In NIPSCO's case-in-chief, residential customers would have received a 22.01% increase following Step 2 rate implementation based on average residential customer usage of 729 kWh. She explained that combining the multi-family rate (Rate 615) into Rate 611 results in lower average overall residential customer consumption, making the comparison of these average residential bill impacts challenging.

Mr. Taylor presented the typical bill impacts for residential customers on Attachment 16-S-C of Petitioner's Exhibit 16-S.

N. Addenda to the Settlement Agreement. Ms. Whitehead explained that Addendum A contains separate terms between NIPSCO and LaPorte County, which were reached to address concerns raised by LaPorte County and that allowed it to not oppose the Settlement. Addendum B contains separate terms between NIPSCO and the RV Group, which were reached to address concerns it raised and that allowed the RV Group to sign the Settlement. She said neither of the addenda have a direct base rate impact, but do, in part, respond to and address concerns raised by both parties. Because there is no direct base rate impact, NIPSCO does not believe the Commission needs to take any action on the addenda. However, they were included to ensure the Commission was aware of these terms, to memorialize NIPSCO's commitments to these parties, and to provide the basis for the positions to either not oppose or to sign on to the Settlement

O. Public Interest. Ms. Whitehead testified that the Settlement is consistent with the public interest. She stated the regulatory compact is, by necessity, a balancing of interests between the utility and its stakeholders. As a general matter, negotiated resolutions to complex issues are consistent with the public interest because the result is the byproduct of input and compromise by the various parties that are directly impacted by the outcome. Ms. Whitehead testified that with respect to the issues addressed in this Cause, NIPSCO was able to reach an agreement that provides for rates and charges sufficient to allow for the recovery of the cost of providing service to its customers, as well as a return of and on its investments in plant and equipment needed to serve its customers. She said the issues addressed in the Settlement and supporting testimony demonstrate the value of compromise in the context of the public interest.

Mr. Latham testified the Settling Parties each made concessions involving considerable give and take on multiple contested issues to reach an overall agreement, reducing the risk and expense of litigation. He testified that the Settlement Agreement, considered in its entirety, serves the public interest by guaranteeing ratepayer savings of $111,616,865 annually, if approved, compared to NIPSCO's case as initially filed. The OUCC considers the Settlement Agreement to be both reasonable and in the public interest, given the facts and applicable law.

8. Opposition to Settlement Agreement. Mr. Inskeep testified as to the CAC's opposition to the Settlement. Specifically, he contends that the Settlement: (1) provides for a modest 30.3% reduction to NIPSCO's overall revenue increase but residential customers will see a much smaller 23.6% reduction; (2) is premised on the acceptance of NIPSCO's ACOSS featuring a 4CP cost allocation that unfairly assigns large portions of production costs to residential customers, even though the Commission recently determined in a different utility's rate case that the 12 coincident peak ("12CP") cost allocation method was superior, and the resulting rates are unjust and unreasonable; (3) contains a term related to NIPSCO conducting an Allocation Study as part of its next rate case that is wholly inadequate; (4) misallocates renewable energy and battery energy storage tax credits, which redistributes millions of dollars each year in tax credits paid for by residential customers, to non-residential customers; (5) provides for an unfairly large portion of the reduction in revenue requirement to go towards reducing the rates of non-residential customers, leaving little benefit and extraordinary rate increases for the residential class; (6) fails to include NIPSCO's proposed multi-family rate, instead lumping this distinct rate class in with Rate 511, leading to rates that far exceed the cost of service for multi-family customers based on NIPSCO's ACOSS; (7) transmogrifies what had been a well-designed low income program into one that mirrors recently failed programs of other Indiana electric utilities, with substantially fewer benefits for eligible customers and without a long-term sustainable funding mechanism; and (8) does not provide adequate ratepayer protections with respect to significant data center load growth being actively negotiated by NIPSCO today.

Mr. Inskeep argued the Settlement is not in the public interest because it is inconsistent with Indiana's affordability pillar and would result in residential rate shock inconsistent with the principles of gradualism and make multi-family residential customers worse off than what NIPSCO presented in its case-in-chief. He said the terms impose a preference for non-residential rate classes over residential customers, resulting in unjust and unreasonable rates. Mr. Inskeep testified that critical residential affordability protections initially proposed by NIPSCO were removed or significantly weakened. He recommended the Commission reject the Settlement or substantially modify its terms.

9. Settlement Rebuttal. Several of the Settling Parties filed settlement rebuttal testimony. The RV Group and Walmart submitted a joinder in specific statements and positions taken by Mr. Taylor and Mr. Dauphinais.

Ms. Whitehead testified that her direct and rebuttal testimony detailed NIPSCO's proposals intended to address customer affordability. She testified the Settlement further reduces NIPSCO's as-filed revenue requirement by over $110 million and contains several provisions designed to address the needs of NIPSCO's lower income electric customers. She stated the agreed revenue reduction is significant and the revenue allocation is fair and reasonable. She stated that while the CAC opposes the Settlement, it contains a number of items that align with the CAC's preferred positions, including no increase in the residential customer charge, a reduction to NIPSCO's ROE, eliminating the security deposit for LIHEAP-qualified customers, and timely phase out of the electric reconnection charge for non-payment. She noted the Settlement is either supported or not opposed by nearly every party and was diligently negotiated in an effort to reach a reasonable outcome that benefits all rate classes. She testified that ultimately, within the constraints available in a highly complex rate case, the Settlement addresses customer affordability for all rate classes through creative problem solving and meaningful adjustments and should be approved in its entirety without modification.

Responding to Mr. Inskeep's contention that the Settlement's overall revenue reduction is modest and inconsistent with the affordability pillar, Ms. Whitehead testified there was a significant focus on affordability by all parties involved in this case. She identified the steps that NIPSCO took to mitigate the bill impact of its initially requested rate relief, which was driven by nearly $2 billion in pre-approved investments in renewable generation assets. She noted that no party, including the CAC, opposed recovery of NIPSCO's generation assets expected to be in service by December 31, 2025. Ms. Whitehead stated NIPSCO's pre-filing mitigation steps included: eliminating paysite convenience fees for customers paying their bill by cash or check; implementing a unique ratemaking construct to reduce NIPSCO's total rate request to: (1) reflect retirement of Schahfer Units 17 and 18 that will occur on December 31, 2025 (i.e., beyond the Forward Test Year) and (2) reduce base cost of fuel related to the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC"); (3) proposing a rate phase-in approach for the Gibson and Fairbanks projects that reduces the cost to customers; (4) proposing depreciation accrual rates that do not reflect the most current estimates for cost of removal associated with the Bailly Generating Station and instead utilizing the estimates supporting current, and lower, depreciation rates; and (5) requesting a lower than recommended ROE.

Regarding the CAC's assertion that NIPSCO's residential customers will experience rate shock, Ms. Whitehead testified that Mr. Inskeep's residential bill presentation is inaccurate. She said the figure only projects NIPSCO's rates through 2026 and does not reflect the Commission's approval of recent rate increases to residential bills for CEI South and Duke of approximately 8.08% and 13.11%, respectively. She testified the Settlement furthers affordability because the Settling Parties agreed to nearly $112 million of reductions to NIPSCO's proposed revenue requirement, primarily relating to NIPSCO's proposed ROE, O&M expense, and depreciation and amortization expense. Ms. Whitehead testified that as a result of the Settlement, NIPSCO estimates that the residential bill increase for an average NIPSCO customer has been reduced from 22.01% to 16.75%, which is broken into multiple steps over several months. She said, by comparison, the agreed revenue requirement reduction in this Cause exceeds that approved in CEI South's electric

rate case (Cause No. 45990) while also incorporating customer affordability measures and reasonably balances the remaining pillars of reliability, resiliency, stability, and environmental sustainability. She acknowledged that a rate increase of any amount can impact customers, particularly those with limited or fixed incomes, but stated the Settlement contains specific measures designed to target assistance to those customers who need it the most.

Ms. Whitehead testified that in addition to the reduction to NIPSCO's proposed revenue requirement, other non-revenue requirement terms in the Settlement that benefit residential customers include: (1) eliminating the $50 customer deposit for NIPSCO's gas and electric customers who receive bill assistance through LIHEAP; (2) no later than the implementation of Step 2 rates, waiver of NIPSCO's $90 electric reconnection charge for electric customers who are disconnected for non-payment of charges; (3) delay of disconnection of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or if forecasted the following two days; and (4) no increase to the monthly residential customer charge of $14. The Settlement also reflects creation of a bill assistance program for NIPSCO's low income electric customers funded by an annual $1.5 million contribution from NIPSCO shareholders and voluntary customer contributions.

In response to Mr. Inskeep's criticism of the bill assistance program provided for in the Settlement, Ms. Whitehead testified that the parties' testimony in this Cause reflects disagreement on the appropriate design of a bill assistance program for low income customers, primarily as to whether a non-bypassable, opt-in, or opt-out program design was appropriate. She said NIPSCO agreed to modify its proposed program to achieve a global settlement in this case with all Settling Parties. She also noted that the Commission has not approved an electric low income program structured like NIPSCO's proposed program, and in Cause No. 45465, the Commission rejected NIPSCO's low income program for electric customers due to its opt-out nature. She testified that while NIPSCO appreciates the CAC's continued support of meaningful bill assistance programs to low income customers, denying or modifying the Settlement based on the program's modified design would serve only to harm the eligible low income customers who stand to benefit from the bill assistance that will now be available. She noted that NIPSCO's shareholder contribution is considerable and Petitioner is committed to targeting all bill assistance funding to customers most in need.

As for the elimination of the multi-family rate proposed in NIPSCO's direct case, Ms. Whitehead testified that the parties could not agree on the strength of NIPSCO's supportive data or how many multi-family customers there are in NIPSCO's territory. She noted that although the CAC recommended approval of NIPSCO's multi-family rate, Mr. Inskeep advocated additional data be provided in NIPSCO's next rate case related to metering and transformer costs. She testified that ultimately, the Settlement addresses the concerns raised by the OUCC, a key stakeholder in terms of representing the interests of residential ratepayers, regarding the level of analysis NIPSCO had undertaken to support its multi-family rate.

Responding to Mr. Inskeep's concern that the Settlement does not provide adequate ratepayer protection with respect to significant data center load growth, Ms. Whitehead testified the Settlement describes NIPSCO's intention as it relates to how large load customers that enter into a contract for electric service will commit to pay the direct, incremental costs associated with serving their load and some portion of the costs of NIPSCO's existing electric system. She

disagreed that such treatment is discriminatory or warrants additional scrutiny and consideration. She said NIPSCO has not entered into any contract for electric service with any large load customer and the Forward Test Year in this case does not include any anticipated load growth associated with any such customer. She indicated Mr. Inskeep's present concerns – which are hypothetical and premature – are best addressed within the context of a regulatory filing related to the approval of any such special contract. She also noted that one of the parties who proposed creating a data center subdocket in this Cause, U.S. Steel, signed on to the Settlement and supports its intended outcome.

Mr. Taylor replied to Mr. Inskeep's testimony on cost allocation and rate design. He disagreed with the CAC's assertion that a 4CP cost allocation for production costs is not reasonable in light of MISO's resource adequacy requirements. He testified that NIPSCO has always had the obligation to provide safe and reliable electric service to its customers in all hours of the year and this obligation existed before MISO was created. He said this obligation does not mean that all hours of the year contribute equally (or at all) to the investments necessary to provide reliable service. Rather, the investments driven by a very small number of hours, which have traditionally been in the summer, have caused the investment in the generation system that is able to provide reliable service in all hours of the year. Mr. Taylor stated this reality has not changed with the seasonal resource adequacy construct, meaning that the investments NIPSCO has made to meet its summer needs allow it to also meet its other seasonal requirements. Mr. Taylor testified that, while NIPSCO's 2024 IRP shows it may need to invest in additional resources to meet the winter season requirements in 2028, this depends on a number of factors and NIPSCO has not proposed any such investments to the Commission. He said Mr. Inskeep's testimony conflates compliance within the IRP models with what seasons are actually binding and driving investment; it is the latter that is relevant.

Mr. Taylor also testified that the CAC's initial position was to abandon the 4CP allocator in favor of the Probability of Dispatch method, or an alternative position of a Peak and Average allocation method. He explained that his rebuttal testimony critiqued the CAC's positions, which the Commission has rejected many times. He also noted that the CAC did not attempt to refute his rebuttal position related to these allocators but instead made a catch-all recommendation to use 12CP, which was provided with no analysis and only one sentence for support.

In response to Mr. Inskeep's continued disagreement with the allocation of PTCs and ITCs using class energy as the basis for allocations and flowing the tax credits back to customers through the FAC, Mr. Taylor testified that all four of the solar and solar plus storage projects NIPSCO seeks to include in its Step 2 rate base were pre-approved by the Commission with authority to pass back PTC and ITC proceeds through NIPSCO's FAC. He explained that no party, including the CAC, opposed this pass back mechanism in those proceedings and the manner in which costs are allocated and recovered through the FAC has not changed since the Commission's approval.

Mr. Taylor explained that PTCs are not generated just because the plant exists; the energy must be produced for a PTC to be created, and the PTCs are nominated in units of dollar per unit of energy produced. He testified that both renewable and fossil-fuel units are subject to variation in output due to a number of factors, including weather, curtailments, and a host of other external influences that can impact production. Mr. Taylor explained that under the CAC's approach, one could argue that fuel expense for a coal or gas resource should be allocated using a production-

demand allocator because the fuel could not be combusted to produce energy without the existence of the plant itself. On the other hand, the plant capacity which serves as the basis for participation within the resource adequacy framework is available without producing energy.

Mr. Taylor testified that, of the total expected tax credits included in the Forward Test Year, roughly 93% are PTCs and the remaining 7% are ITCs. He explained that ITCs differ from PTCs in that the tax credits are not a function of production but rather a function of the existence of the plant (and meeting the eligibility requirements) but noted that the Commission has already directed NIPSCO to return the ITCs through the FAC, which is based on energy. Mr. Taylor explained that changing the ITC allocation to the production-demand allocator would result in a reduction to the residential revenue target of approximately $350,000 before FAC impacts, but this would not result in realized lower rates for residential customers as they are already receiving a significant subsidy from other customers. He also indicated that billing system adjustments would be needed to code a demand allocation into NIPSCO's FAC, an undertaking that is neither quick nor cost-free. Additionally, Mr. Taylor explained that Mr. Inskeep's recommendation to adjust the PTC/ITC allocation as a single item creates a process concern because a holistic review of cost allocation is needed to ensure equity across all customer groups. He said a holistic review is necessary to ensure there are no unintended consequences, that all sides are considered, and interactions between different changes are fully vetted and understood.

Regarding the CAC's concerns with the steps taken in the Settlement to apportion the agreed reduction in NIPSCO's revenue requirement to the customer classes, Mr. Taylor said the steps taken are nearly identical to those taken in the 45772 Settlement – including setting the revenue increase for the residential class at slightly above system average. He explained that the 45772 Settlement also included a term regarding the step down of Rate 531 allocated demand and the present Settlement merely implements that approved term. Mr. Taylor also noted that, while Mr. Inskeep expressed concern about the impact of NIPSCO's rate request on schools, he did not acknowledge that schools fall within the "non-residential" rate classes and stand to benefit from the needed mitigation steps included in the Settlement.

Mr. Taylor responded to the CAC's criticism that the residential rate class will experience only a 23.6% revenue requirement reduction when the overall Settlement revenue is reduced by 30.3%. Mr. Taylor stated that a system average increase not only prohibits any movement towards class parity with cost of service, but exacerbates the cross subsidy to the residential class. He said that his Table 1 shows that even under a 12CP production allocation, residential customers would still receive a subsidy of over $99 million, negating the CAC's opposition to the residential class revenue increase under the Settlement. He said that, even in a litigated outcome where the CAC's preferred outcome of 12CP is approved, it is likely a residential class revenue increase would be at or above the Settlement amount.

In response to the CAC's concerns about the absence of a multi-family rate, Mr. Taylor testified that not implementing such a rate at this time was part of the negotiation process in response to both the CAC's and the OUCC's concerns with the scope of data to support NIPSCO's proposal. He noted that Mr. Inskeep was initially critical of NIPSCO's analysis regarding the evaluation of metering and transformer costs, resulting in the CAC's recommendation for a more comprehensive evaluation in NIPSCO's next rate case. Mr. Taylor stated that the Settling Parties ultimately agreed NIPSCO would not create the multi-family rate at this time, but to conduct

further study. Mr. Taylor further testified that although the proposed multi-family rate was an effort to reduce intra-class subsidies, under the Settlement, residential customers continue to be treated equally and as a homogenous rate class.

Mr. Deupree disagreed with the CAC's position that the Settlement provides inadequate benefits to residential ratepayers. He testified that as originally proposed, NIPSCO's overall revenue increase was $368.7 million, or a 20.1% increase in Petitioner's total revenues. Under the Settlement Agreement, this proposed overall revenue increase is reduced by $111.6 million to $257.0 million. He explained that all major rate classes benefit from the reduction in NIPSCO's proposed rate increase, including residential customers. Under NIPSCO's case-in-chief, residential ratepayers would have received a $134.1 million rate increase ($124.5 million increase for single-family Rate 511 and $9.6 million for multi-family Rate 515). Under the Settlement Agreement, this revenue increase is reduced to $103.4 million, a savings for residential ratepayers of approximately $30.7 million.

Mr. Deupree testified that the Settlement reasonably resolves the differences among the parties on the ACOSS. He stated the Settlement Agreement attempts to balance some parties' desire to reduce residential subsidies under NIPSCO's current rates with concerns over the accuracy of Petitioner's ACOSS due to the allocation of costs associated with production plant.

As for the CAC's concerns regarding the allocation of benefits associated with tax credits, Mr. Deupree explained that NIPSCO's proposed pass back of tax credit proceeds to customers through the FAC, which utilizes an energy allocator, is consistent with the Commission's CPCN orders. He stated that while there are arguments for the allocation of ITC benefits on the basis of underlying production plant, he does not agree with the proposal to allocate PTC benefits on the basis of production plant in the future. Mr. Deupree testified that PTCs accrue with renewable generation, so NIPSCO will earn more PTC benefits in years when its solar and wind generators produce more power than in years in which less renewable energy is generated; therefore, Mr. Deupree concluded that PTC benefits are directly associated with total customer energy requirements and not peak demand requirements. He testified that the Settlement Agreement recognizes NIPSCO will comprehensively review cost allocations before its next base rate case, including allocation of energy-related costs in base rates and the FAC and RA trackers.

Mr. Deupree stated that his direct testimony explained the OUCC's concern that NIPSCO's multi-family rate proposal was supported by very limited analysis and research that may not be representative of actual residential customers in Petitioner's service territory. Specifically, Mr. Deupree testified that NIPSCO's proposal was supported by a load research sampling of only 127 residential customers out of a residential customer base of 431,840 (only 0.03%). Likewise, only 21 of these load research customers were found to be multi-family customers, while NIPSCO estimated there were approximately 68,195 multi-family customers on its system. He testified that although Mr. Inskeep's testimony opposing the Settlement describes Petitioner's analysis as robust, his direct testimony raised concerns similar to those of the OUCC. Mr. Deupree stated he disagrees that not implementing the multi-family rate disproportionately harms lower-income households. He said it has not been demonstrated that all, or even most, prospective multi-family customers are low income customers. Mr. Deupree testified that the agreement not to implement the multi-family rate reflects the OUCC's concern that establishment of a separate multi-family rate in the current proceeding would have likely resulted in single-family customers paying higher

rates, harming these low income customers. Mr. Deupree explained that under the Settlement, NIPSCO will continue to collect data on residential customer housing types to better identify its multi-family customers and the differences in the costs to serve these customers compared to single-family customers and provide the results of this additional study to the CAC and the OUCC. He stated that this study should provide greater insight for facilitating a more robust proposal in future proceedings.

Mr. Deupree testified that the Settlement Agreement modifies NIPSCO's proposed bill assistance program from an opt-out program to a voluntary, opt-in program. He stated that NIPSCO also agreed to make an annual, non-recoverable, $1.5 million contribution from its shareholders, as compared to its initial proposed $400,000 shareholder contribution. Mr. Deupree stated this reduces the potential impact of the proposed program on ratepayers, including low income customers, while still enabling assistance from customers who choose to participate in Petitioner's assistance program. He noted that involuntary assistance programs similar to what NIPSCO originally proposed have been rejected by the Commission in multiple prior proceedings. Mr. Deupree stated the increase in Petitioner's financial contribution and the change to a voluntary assistance program under the Settlement Agreement mitigate the Commission's previous concerns.

Mr. Deupree testified that the Settlement Agreement includes NIPSCO's stated intent that new data center customers pay for all direct incremental costs associated with serving these customers. The Settlement Agreement also conveys the intent that new data center customers will pay a portion of existing system costs, thus reducing existing customers' rates. He explained that the CAC appears to be concerned that the Settlement Agreement language is broad and fails to expressly define what is included in "direct, incremental costs" or what is meant by "some portion" of existing system costs. Disagreeing with those concerns, Mr. Deupree said the Settlement Agreement preserves flexibility in considering individual proposals from potential data center customers while recognizing NIPSCO's commitment to ensure that the addition of these new customers does not result in higher costs for NIPSCO's existing customers. It also recognizes NIPSCO's commitment to potentially reduce rates to existing customers by allocating certain existing system costs to new data center customers.

Mr. Dauphinais responded to the CAC's suggestion that the Commission should reject the Settlement because it uses a 4CP method for production costs in the underlying cost of service study instead of a 12CP allocation. Mr. Dauphinais stated this provision in the Settlement is consistent with the cost of service methodology approved by the Commission in prior NIPSCO electric rate cases, including Cause No. 45159 in which the Commission rejected the CAC's arguments. Mr. Dauphinais reiterated that the seasonal requirements do not alter the fact that the NIPSCO system retains a clear summer-peaking status that drives its capacity needs, and that the production assets acquired by NIPSCO to meet its summer (June through September) peak demand continues to inherently provide sufficient capacity to meet its MISO requirements for the rest of the year. He pointed out that Mr. Inskeep's opposition testimony does not rebut that analysis.

Mr. Dauphinais stated that the Commission's approval in Cause No. 46038 of Duke's proposal to use a 12CP allocation of production costs does not indicate that the Settlement's agreement to use a 4CP method is unreasonable. He explained that the Duke case involved

significantly different circumstances and noted that although the Commission had approved a 4CP study in Duke's prior rate case, the Duke system had been allocated on a 12CP basis for many years prior to that. By contrast, Mr. Dauphinais highlighted that, in this case, NIPSCO proposed a 4CP allocation for production costs, consistent with its established cost of service studies as approved over a number of past rate cases.

Mr. Dauphinais testified that the situation here parallels CEI South's electric rate case, Cause No. 45990, wherein CEI South sponsored a cost of service study utilizing a 4CP allocation for production assets, consistent with its longstanding methodology approved by the Commission in past cases. He said the Commission approved a settlement among less than all the parties which adopted the 4CP allocation for production costs. He noted that, in that case, the CAC opposed that settlement and argued that the 4CP methodology was unreasonable. Mr. Dauphinais stated the Commission approved the settlement in the CEI South case the week following the order in Duke's rate case, which shows the Commission did not regard the adoption of Duke's proposed cost of service study to be a barrier to approval of the cost of service terms in the CEI South settlement.

Mr. Dauphinais testified that the CAC attempted to distinguish the CEI South case on the premise that there the Commission only rejected proposals for energy-based allocation methods, whereas in this case the CAC proposed a 12CP allocation for production costs. But, in both cases, the CAC's litigation position advocated an energy-based methodology, particularly the Probability of Dispatch method. He explained that in the CEI South case, the Commission not only rejected energy-based methods, but specifically found that CEI South's system does not pass the three FERC tests which provide guidance as to whether the 12CP method would be appropriate. He said the same status supports the cost of service terms of the Settlement in this case.

Mr. Dauphinais stated that the Settlement here, like that approved in the CEI South case, provides for a substantial reduction in the revenue increase sought by the utility, to the benefit of all customer classes, while providing for continued use of the utility's established cost of service methodology. In addition, he noted the Settlement in this case, unlike the CEI South settlement, was entered into and endorsed by the OUCC and other parties representing multiple customer classes. Thus, he disagreed with any attempt to characterize the Settlement as favoring industrial customers to the detriment of residential customers.

Mr. Dauphinais stated that Mr. Inskeep's objection to the agreed reduction in Tier 1 demand levels for the Rate 631 class does not raise any valid concern. He explained that the process to progressively reduce the Tier 1 demand level for Rate 631 customers – both to bring imputed demand for cost allocation purposes closer to actual contract demand and to move eligible customers closer to the tariff minimum – was a feature of the 45772 Settlement. Mr. Dauphinais testified that the computation of adjustments to Tier 1 demand is correlated to reductions in the costs of legacy coal plants embedded in base rates and the agreed reduction in this case implements the 45772 Settlement. He explained that the difference between the 164 MW initially proposed by NIPSCO in its direct case and the 162 MW provided for in the Settlement is attributable to the substantial reduction in the revenue requirement under the Settlement. He said those reductions result in less coal plant-related costs being reflected in NIPSCO's base rates, and hence have a modest effect on the computation of new Tier 1 demand levels.

Mr. Dauphinais testified that Mr. Inskeep's position regarding the revenue distribution provision in the Settlement is not reasonable. He explained that NIPSCO's existing rate structure features substantial inter-class subsidies, with several rate classes paying rates in excess of system-average while the residential rate yields revenue significantly below a system-average return. He testified that several parties supported reductions in the current subsidies for the residential class and that the Settlement starts with the revenue distribution proposed by NIPSCO but then devotes a defined 25% component of the agreed decrease below NIPSCO's proposed revenue to reducing subsidies with the remainder allocated to all classes. Mr. Dauphinais testified that this provision mirrors the subsidy mitigation term in the 45772 Settlement. He stated that the CAC's effort to institutionalize a clear deviation from cost-based rates by maintaining the subsidy is unreasonable.

Ms. Schuepbach responded to Mr. Inskeep's allegations regarding cost shifting or subsidization by stating they are inaccurate for several reasons. First, the Commission found in Cause Nos. 45159 and 45772 that Rate 831/531 is not subsidized. Second, the proposed demand allocation to Rate 631 is consistent with the 45772 Order and the Settlement, which provides that future reductions to Tier 1 load and cost allocations will be correlated to further reductions in the costs of legacy coal assets reflected in NIPSCO's base rates. Third, Rate 831/531/631 has historically subsidized other customer classes and continues to do so. Ms. Schuepbach explained that, at a minimum, this rate is overallocated costs in production demand, transmission expenses, and FAC expenses. Ms. Schuepbach testified that Rate 631 is set to parity for rate mitigation (revenue distribution), meaning the rates will be set to collect revenues based on the ACOSS. However, Ms. Schuepbach stated that the ACOSS over-allocates expenses and Rate 631 customers are already paying more than their cost of service, particularly for legacy coal generation costs they no longer use.

Ms. Schuepbach disagreed with Mr. Inskeep that the system rate increase should be applied to each customer class. She explained that under the Settlement Agreement, Rate 631 is set to parity with a rate increase of 10.32% or $15.5 million. Mr. Inskeep, however, recommended a rate increase of 14.05% or $21.0 million (14.05% x $149,681,610), which would harm Rate 631 customers by increasing their revenue requirement by $5.6 million ($21,029,048 - $15,450,084). She expressed several concerns with the CAC's suggestion to apply the same rate increase to each customer class. First, she stated this approach goes against industry standard cost of service and ratemaking principles. Citing *Bonbright Principles of Public Utility Rates*, she testified that one of the described principles is the need for fair and equitable rates, or rates that represent the cost of service. Anything beyond cost-based rates means that there is subsidization among and/or within the customer classes. In addition, Ms. Schuepbach testified that the National Association of Regulatory Utility Commissioners' *Electric Utility Cost Allocation Manual* states that cost of service studies are one of the basic tools of ratemaking and explained there is no point to conducting a cost of service study if the system rate increase will be provided equally to all customer classes.

Second, Ms. Schuepbach testified that the CAC's proposal goes against NIPSCO's statement that the ACOSS is used as a guideline for class revenue levels and rate structures and its desire to move toward cost of service, while implementing moderation. She stated any proposal that is not moving classes towards their cost of service is compounding the subsidization issue, making ongoing subsidization worse for certain classes, like the residential class. She explained that if any revenue mitigation is done, it should be in a way that reduces subsidies and moves

classes closer to their actual cost of service, rather than amplifying and prolonging the subsidization problem.

Ms. Schuepbach testified that she agrees that the data centers need to pay their fair share of embedded costs for joining the NIPSCO system. While she agreed with Mr. Inskeep that the data center load is a major issue that needs to be addressed transparently and in detail with enforceability, she disagreed with Mr. Inskeep that the Settlement Agreement should be rejected or modified for the Commission to effectively deal with the issue, which is now pending in another proceeding.

Ms. Schuepbach concluded that the Settlement Agreement is fair, reasonable, and in the public interest. She testified that the Settlement terms keep NIPSCO profitable and will allow US Steel to remain a customer on the NIPSCO system. She stated that other customer classes benefit as well because of reductions in the overall system revenue requirement and the settlement class revenue allocators. She recommended that the Settlement Agreement be approved by the Commission.

10. Commission Discussion and Findings. At the outset, we recognize that the Commission previously approved most of the capital investment additions that NIPSCO proposes to include in its rate base in this proceeding.[14] These include the development and acquisition of four solar and solar plus storage facilities that make up approximately $2 billion (approximately 68%) of NIPSCO's rate base additions. NIPSCO's rate base request also reflects inclusion of approved TDSIC investments of $769.5 million (approximately 25% of the capital additions). The remaining portion of NIPSCO's rate base request (approximately 7%) relates to ongoing capital investment in other assets, including information technology and customer-driven capital work through new underground electric services, new business electric extensions, and new customer substations.

Even with the various preapproved projects discussed above, the record demonstrates that there were a number of highly contested issues in this Cause. Despite the complexity and number of issues, the Settling Parties reached a comprehensive agreement. Although it is opposed by one party, those joining or not opposing the Settlement Agreement and Addenda represent a wide variety of interests and included residential, commercial, and industrial customers. A complete copy of the Settlement Agreement is attached to this Order, including the schedules supporting the calculation of the agreed Settlement revenue requirement based on the 12-month period ending December 31, 2025 (Joint Exhibit A to the Settlement), the new depreciation rates (Joint Exhibit B to the Settlement), and the redacted Rate 631 contract demand (Confidential Joint Exhibit C to the Settlement). These attachments are incorporated into and made a part of this Order by reference.

The Settlement Agreement represents the Settling Parties' proposed resolution of the issues in this Cause. As the Commission has previously discussed, settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co., Inc.* 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement

[14] *See*, Cause No. 45936 (IURC 1/17/2024), Cause No. 46028 (IURC 8/14/2024), Cause No. 46032 (IURC 8/21/2024), Cause No. 45557 (IURC 12/28/2021), and Cause No. 46025 (IURC 9/25/2024).

"loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (quoting *Citizens Action Coal. Of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.*, 664 N.E.2d at 406.

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

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

As detailed above, the Settling Parties made numerous compromises to reach an agreement. NIPSCO, in its initial case-in-chief provided evidence to support a revenue deficiency of $369 million, reflective of an overall 20.15% revenue increase. As shown by Paragraph B.1.(a) of the Settlement Agreement, the Settling Parties agree that NIPSCO's base rates should be designed to produce $2,086,642,669 prior to application of surviving Riders. The increase in base rates results in an increase from current base rates of $257,043,752 (approximately 16.75%), which is a decrease of approximately $111,616,865 (30%) from the amount originally requested by NIPSCO in its case-in-chief.

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

A. <u>Reasonableness of Settlement Agreement</u>. The CAC argues that several of its concerns were inadequately addressed in the Settlement Agreement and therefore recommends the Commission reject the Settlement or substantially modify its terms. We address each of the CAC's major concerns below but, based on the evidence presented, we are not persuaded by the CAC's arguments to reject or modify the Settlement. The Settling Parties have

sufficiently shown that the Settlement provides reasonable resolutions to the disputed issues. We find the Settlement Agreement substantially reduces NIPSCO's requested relief, reasonably addresses Indiana's five pillars as set forth in Ind. Code § 8-1-2-0.6 ("Five Pillars") of affordability, reliability, resiliency, stability and environmental sustainability, and is consistent with the balancing this Commission has been charged to perform by the Indiana General Assembly.

1. Cost Allocation and Rate Design. The Settlement ACOSS reflects the settled revenue requirement, which remains consistent with the structure and methodologies of the cost of service study used by NIPSCO in its case-in-chief. The ACOSS uses a 4CP methodology to allocate production costs and a minimum system study to determine a customer component for distribution costs. In addition, while adopting NIPSCO's cost of service structure and methodologies, the Settlement also includes commitments by NIPSCO to study the applicability of certain classification and allocation methodologies in an Allocation Study and present them as part of its next general rate case.

The CAC acknowledged that except for the use of an updated revenue requirement and other limited modifications, such as the reduction to Rate 631's allocated demand, the Settlement ACOSS is essentially consistent with the structure and methodologies used by NIPSCO. However, the CAC asserted that this is an unreasonable and unbalanced resolution to the cost allocation issues raised by the CAC and other parties. In particular, the CAC disagreed with the Settling Parties' agreement that NIPSCO use a 4CP cost allocation method for production costs and asserted that a 12CP cost allocation method is more reasonable and should be adopted as it was for Duke in Cause No. 46038. The CAC also criticized the Settling Parties' adoption of NIPSCO's proposed allocation of the ITC and PTC benefits in base rates and in the FAC, instead recommending that the allocation of these benefits mirror the allocation that is ultimately adopted in this proceeding for the costs of generation and battery storage facilities. Finally, the CAC disagreed with the modification of Rate 631 Tier 1 demand that further reduces the production costs allocated to Rate 631.

The record establishes that NIPSCO's system peak occurs in the summer and that its system does not satisfy the three FERC tests that guide determination as to whether a change to a 12CP methodology is appropriate. In addition, the generation investments included in the Forward Test Year are driven by peak summer hours and allow NIPSCO to provide reliable service in all hours of the year. We also note that a key difference between NIPSCO's and Duke's electric service territories is the penetration level of natural gas heating for its residential customers. The comparatively lower use of electric heating in NIPSCO's service territory materially shifts the demand curve to the summer, bolstering NIPSCO's support of the 4CP methodology. NIPSCO, Duke, and CEI South all participate in MISO. The MISO seasonal construct, however, is not determinative of how each utility should allocate its production costs. The cost allocation appropriate for each utility is, and must be, a function of its cost to serve. The Settlement Agreement's reliance on the 4CP allocation methodology for production costs under the facts presented in this case is reasonable and supported by the record.

Regarding the agreed upon allocation of PTCs and ITCs in the Settlement Agreement, the record reflects disagreement among many of the parties on how these benefits should be allocated. As noted by the Settling Parties, the Settlement's proposed treatment is consistent with three prior Commission orders providing for the pass back of PTCs and ITCs to customers through NIPSCO's

FAC. NIPSCO has also agreed to conduct an Allocation Study to further address cost allocation issues in its next base rate case. CAC's arguments fail to recognize that energy must be generated by a solar facility to generate PTCs and that any adjustment for ITCs would likely be de minimis due to the continued residential class subsidy. Therefore, we are not convinced by CAC's arguments that the Settling Parties' agreement on the allocation of PTCs and ITCs is unreasonable.

The step down of Rate 631 Tier 1 allocated demand in the Settlement Agreement relates to reductions in coal plant-related costs being reflected in NIPSCO's base rates. This treatment is consistent with the methodology previously approved in the 45772 Order and we were not presented with sufficient reasons for this methodology to change. Therefore, we find that the incorporation of NIPSCO's ACOSS into the Settlement Agreement is reasonable and appropriate, and the resulting cost allocation in the Settlement Agreement is approved. While we find NIPSCO's ACOSS is supported by the evidence, we are encouraged by NIPSCO's commitment to conduct an Allocation Study to review its production allocation on an energy basis, particularly as the share of non-dispatchable resources in its generation portfolio increases. NIPSCO shall follow the terms of the Settlement Agreement, including Section 11(b) regarding production and distribution classification and allocation.

Finally, while not addressed in the CAC's testimony opposing the Settlement, Mr. Inskeep opposed in his direct testimony NIPSCO's recovery of the amortization expense associated with its Economic Development Rider from non-participating customers because the Rider benefits utility shareholders. However, as noted by Mr. Weatherford, the Commission has previously authorized NIPSCO with deferral accounting authority to recover in a future rate case the associated customer discounts in Cause No. 45159. Accordingly, we find the treatment proposed by NIPSCO, as incorporated in the Settlement Agreement, remains reasonable and should be approved.

2. <u>Revenue Distribution</u>. In the Settlement Agreement, the Settling Parties acknowledged that, as presented in NIPSCO's case-in-chief, certain rate classes are being subsidized by several other rate classes. Thus, the Settling Parties agreed to mitigate a portion of the subsidy concerns in a manner consistent with similar concerns that were raised and addressed in the 45772 Settlement.

The CAC noted that while the Settlement Agreement provides for a 30.3% reduction to the revenue requirement from NIPSCO's original filing, residential customers will experience only a 23.6% reduction to their revenue requirement relative to NIPSCO's case-in-chief. Mr. Inskeep argued that this results in an unbalanced Settlement mitigation that benefits non-residential customers. As an alternative, Mr. Inskeep proposed assigning the same percentage increase to each existing customer class, i.e., equal to the system average increase. Then, prior to NIPSCO's next rate case, NIPSCO could conduct a holistic examination to more accurately identify existing cross-subsidization occurring in rates and propose the appropriate cost allocation modifications and mitigation steps to address any identified cross-subsidies, while taking into consideration gradualism and other important public policy objectives.

We recently modified the revenue distribution in an opposed settlement by adopting a lower cap on the agreed system average overall increase for the residential class in CEI South's last rate case, Cause No. 45990. In that case, the tendered settlement limited the increase to each

class to no more than 1.35 times the system-average increase, and we found it appropriate to narrow that band to no more than 1.15 times system average. *CEI South*, Cause No. 45990 at 114-115 (IURC Feb. 3, 2025). Under the Settlement here, however, the residential increase of 14.75% is only 1.05 times the system average of 14.05% and well within the constraint we found appropriate in CEI South's rate case. Pet. Ex. 16-S, Att. 16-S-A at 1. In that case, we also acknowledged that "[a]ffordability is a key consideration across all customer classes, and the desire to provide affordability across the board supports a revenue requirement increase that is as evenly borne as practical, while considering any subsidies that may be identified by the ACOSS." *CEI South*, Cause No. 45990 at 115.

The record is clear that, under the analysis of multiple cost of service experts in this Cause, NIPSCO's residential class is being subsidized by the rates paid by other customer classes. In addition, even under the 12CP allocation methodology proposed by the OUCC on direct, and as the CAC now proposes, the residential class would continue to receive a $99 million subsidy. We are not persuaded by the CAC's arguments and find that the CAC's recommended across the board system average would only perpetuate and potentially grow the residential class subsidy, undermining customer affordability in deviation from cost causation principles.

Accordingly, we find that the Settlement Agreement reflects fair and appropriate compromises made by representatives of the majority of customer classes, while recognizing the policy of gradualism, to reach a distribution that is as evenly borne as practical considering the identified interclass subsidy. The agreed revenue distribution as presented in the Settlement Agreement is reasonable, balanced, and approved.

3. Multi-Family Rate. Under the Settlement Agreement, NIPSCO's proposed multi-family rate will not be implemented. Instead, NIPSCO agrees to collect additional data on residential customer housing to further identify multi-family customers and analyze the cost differentials between single- and multi-family customers for consideration in its next base rate case. NIPSCO also agrees to meet with interested stakeholders and share its analysis prior to filing its next base rate case.

The CAC asserted that by not adopting NIPSCO's multi-family rate, the Settlement will significantly harm multi-family customers and produce rates that are unjust, unreasonable, and in excess of what NIPSCO considered to be the cost to serve such customers, even prior to the reduction in revenue requirement included in the Settlement.

The evidence demonstrates that both the OUCC and the CAC took issue with the scope and robustness of NIPSCO's data to support the proposed multi-family rate and how many multi-family customers are in NIPSCO's territory. However, while the OUCC opposed approval of the multi-family rate, the CAC recommended approval along with a recommendation that NIPSCO conduct a more comprehensive evaluation to be provided in its next rate case.

Based on the evidence presented, we find the Settlement Agreement reasonably resolves the parties' dispute by foregoing implementation of the multi-family rate in this Cause but committing NIPSCO to further study its multi-family customers. We find this resolution reasonable, especially given the OUCC's concern that creation of the multi-family rate could create more interclass subsidies. As Mr. Deupree noted, the evidence is insufficient to conclude

that implementing the multi-family rate disproportionately harms lower-income households because it has not been demonstrated that all, or even most, of NIPSCO's multi-family customers are low income customers. Thus, we find NIPSCO's agreement to continue collecting data, including using information from Advanced Metering Infrastructure ("AMI") that is anticipated to facilitate these efforts after being fully deployed in NIPSCO's service territory, should provide greater insight for purposes of potentially facilitating such a proposal in future proceedings.

4. Low Income Program. The Settlement provides for approval of NIPSCO's proposed low income program with the following changes: (1) NIPSCO will modify the program from an opt-out program to a voluntary, opt-in program; and (2) NIPSCO will make an annual, below the line, shareholder contribution of $1,500,000.

The CAC recommended the Commission approve the low income program NIPSCO proposed in its case-in-chief, as modified by Mr. Inskeep's recommendations in his direct testimony. Mr. Inskeep stated that the changes agreed to in the Settlement dramatically reduce the funding for the program, meaning eligible customers will receive substantially smaller benefits. Thus, he concluded that NIPSCO's original proposal provided program design and funding levels that are more reasonable to address affordability.

Under the Settlement Agreement, NIPSCO's proposed low income program has been modified in response to concerns raised by the OUCC as well as consideration of prior Commission orders regarding ratepayer-funded bill assistance programs. As presented by the Settling Parties, the low income program remains an important measure intended to address utility affordability for residential customers who face income challenges. The OUCC noted that the program as modified will reduce the potential impact on ratepayers, including low income customers, while still enabling assistance from customers who choose to participate in the assistance program. In addition, NIPSCO's shareholder contribution has substantially increased from its case-in-chief (from $400,000 per year to $1,500,000 per year) and will provide bill assistance to customers in need. When the Settlement Agreement is considered in its entirety, we find the agreed low income program balances the consumer parties' interests and concerns, including those expressed by the CAC, with NIPSCO's interest in providing bill assistance for its low income customers. We, therefore, find the stipulated low income program is reasonable and should be approved.

5. Data Centers. While several parties advocated for the creation of a subdocket to address issues related to new large load customers, the Settling Parties acknowledged in the Settlement that NIPSCO has made a filing with the Commission related to its strategy to serve such customers. NIPSCO expressed its intent for any large load customer with which it enters into a contract for electric service will commit to pay the direct, incremental costs associated with serving that load and some portion of NIPSCO's existing electric system. If NIPSCO should enter into such a contract, NIPSCO also commited to making a timely filing to pass back to existing customers the revenues collected that are related to the recovery of costs associated with the existing electric system. Additionally, while other parties are not precluded from making arguments in other dockets related to large load customers, NIPSCO is precluded from arguing it should not pass back any portion of these identified revenues.

The CAC argued the Settlement does not adequately resolve the issues raised by several parties with respect to new large load customers like data centers. Mr. Inskeep stated the Settlement fails to meaningfully address data centers, which he contended should pay (like other ratepayers) the full embedded cost of service – not merely "direct, incremental" costs and "some portion" of embedded costs. Mr. Inskeep argued that a subdocket to holistically examine issues would be a more appropriate forum to collect and weigh the evidence and determine the appropriate path forward, rather than approving a vaguely worded term containing inaccurate statements expressing an intention for further discriminatory treatment.

The evidence demonstrates that NIPSCO has not entered into any contract for electric service with a large load customer and the Forward Test Year in this case does not include any costs or expected revenues associated with data center load. Thus, we agree that the CAC's concerns regarding cost recovery and discriminatory treatment, which are hypothetical and premature at this time, are best addressed in a regulatory filing related to the approval of any special contract. A subdocket to this Cause to address data centers is neither necessary nor appropriate. As noted by the OUCC, the Settlement Agreement preserves flexibility in considering individual proposals from potential data center customers, maintains the ability of parties to raise issues in other proceedings, and recognizes NIPSCO's commitment to ensure that the addition of these new customers does not result in higher costs for existing customers. NIPSCO is also precluded from contesting the pass back of large load contract revenue related to the recovery of existing electric system costs. Accordingly, we find that the Settlement Agreement maps out a reasonable approach for addressing the issues raised regarding potential new large load customers in NIPSCO's service territory.

6. <u>Residential Customer Affordability</u>. The CAC generally contended the Settlement is inconsistent with Indiana's affordability pillar and public interest. Mr. Inskeep asserted that many of NIPSCO residential customers will experience rate shock and accelerating unaffordability. He stated the Settlement discards some of the most critical residential affordability protections initially proposed by NIPSCO, such as ratepayer-funded income-qualified bill assistance, a multi-family rate, and limiting the residential class rate increase to the system average increase. He asserted that the modest consumer protection provisions included in the Settlement do little to mitigate the unprecedented rate shock residential customers will experience.

As noted earlier, the primary driver of NIPSCO's requested rate increase is the capital projects that have received preapproval by the Commission, which limits the ability to mitigate the overall rate increase. The Settlement Agreement in this Cause results in over $111 million in reductions to NIPSCO's as-filed revenue requirement and an over $30 million reduction to the proposed revenue increase for the residential class. The Settlement also reflects a number of measures intended to address affordability and residential customer needs, including elimination of the $50 customer deposit for NIPSCO's gas and electric customers receiving bill assistance through LIHEAP; waiver of NIPSCO's $90 electric reconnection charge for electric customers who are disconnected for non-payment of charges (beginning no later than implementation of Step 2 rates); delay of disconnection of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or if forecasted the following two days; and no increase to the monthly residential customer charge of $14. The Settlement also reflects the creation of a bill assistance program for NIPSCO's low income electric customers funded by

voluntary customer contributions and a significant annual $1.5 million contribution from NIPSCO shareholders. In addition to these benefits, NIPSCO's commitment to holistically study its cost of service classifications and allocations in an Allocation Study have the potential to further reduce residential rates in the future. Taken together, we find the Settlement Agreement reasonably addresses customer affordability consistent with Indiana's Five Pillars and is in the public interest.

B. ARP for Remote Disconnection/Reconnection. The Settling Parties agree in Section B.14. of the Settlement Agreement to the approval of the ARP for remote disconnect/reconnect and Mr. Inskeep did not oppose this portion of the Settlement Agreement.

Ms. Whitehead testified that NIPSCO requests approval of an ARP to waive the requirements in 170 IAC 4-1-16(f) and to permit remote disconnection in lieu of an in-person visit by a utility representative prior to disconnection. She explained that NIPSCO received approval for its AMI Project through its electric TDSIC Plan approved in the Commission's December 28, 2021 Order in Cause No. 45557. NIPSCO expects approximately 205,000 of its electric customers will have AMI meters installed by the end of the Forward Test Year (i.e., December 31, 2025). She said AMI meter technology provides for the efficient and safe remote capability to disconnect and reconnect electric service.

Ms. Whitehead explained NIPSCO's business practice as it relates to customer contact information like phone numbers and email addresses, how customers are currently notified of a service disconnection due to non-payment, and the proposed procedure for notifying customers of a service disconnection for non-payment using AMI technology. She noted that certain customers will be exempt from remote disconnection, including medical alert customers, AMI opt-out customers, and those customers without documented telephone numbers or email addresses. Ms. Whitehead testified that if the ARP is approved, NIPSCO will undertake a campaign to notify its customers of its ability to remotely disconnect/reconnect upon our approval of the requested waiver.

In his direct testimony, but not his settlement opposition testimony, Mr. Inskeep opposed NIPSCO's remote disconnection proposal because it would make it easier for utilities to disconnect residential ratepayers without adequately informing them through an on-premises visit. He argued that NIPSCO's proposed ARP for remote disconnection is inconsistent with the requirements of Ind. Code ch. 8-1-2.5. No other party opposed the request, but Ms. Paronish recommended enhancements to NIPSCO's communications plan, including, to the extent NIPSCO has the information, utilizing all three communication mechanisms – a phone call, a text message, and an email communication – to contact a customer prior to disconnection. She also proposed additional communication language and methods to notify customers that service disconnection will be conducted remotely.

On rebuttal, Ms. Whitehead explained that NIPSCO was modifying its communications plan based on the OUCC's recommendations. She said, as modified, NIPSCO's customers will be adequately informed that their service is being disconnected for non-payment. Ms. Whitehead also responded to Mr. Inskeep's concerns, explaining why NIPSCO's requested waiver of the requirements in 170 IAC 4-1-16(f) is in the public interest and meets the statutory criteria. She also provided Table 1 in Petitioner's Exhibit 2-R, which details NIPSCO's response to each

additional communication method proposed by the OUCC and provided NIPSCO's modification to the language in its messaging.

Given that Petitioner's waiver request is part of an ARP, in addition to our overall approval of the Settlement Agreement, Ind. Code § 8-1-2.5-6(a)(1)(A) requires the Commission to determine whether approval of the proposed ARP is in the public interest by considering the following four criteria enumerated in Ind. Code § 8-1-2.5-5(b):

> (1) whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;
>
> (2) whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;
>
> (3) whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency;
>
> (4) whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

The Commission's rule at 170 IAC 4-1-16(f) provides that, prior to disconnection of electric service, a NIPSCO employee is required to, among other things, make an on-site premises visit. The record shows that, due to the advancement in technology and through the use of AMI, there are safer and more effective ways to notify a customer of potential disconnect due to nonpayment and to ultimately disconnect the customer than what was historically available when the rule was promulgated. Modern technology allows NIPSCO to notify the customer multiple times and in many different forms in the event of a potential disconnect. Further, through the use of AMI and remote connect/disconnect capability, NIPSCO does not need to be physically present on the customer's premises to connect or disconnect service, promoting efficiency. Thus, the goals of 170 IAC 4-1-16(f) – to sufficiently notify a customer of potential disconnect and to identify oneself while on a customer's property – can be achieved in a safer and more effective way through the use of modern technology.

The record also reflects that Commission approval of NIPSCO's proposed ARP will be beneficial for the utility, its customers, and the state, as NIPSCO will be able to complete disconnects and reconnects more safely, quickly, and efficiently through the remote capabilities of AMI than through the traditional truck roll and field personnel being dispatched to the customer's premise. Remote disconnection will improve safety for NIPSCO's workers and remote reconnection will support customer safety by restoring service faster.

We also find that the exercise of the Commission's jurisdiction would inhibit NIPSCO from competing with other providers of functionally similar services or equipment insofar as it would deny NIPSCO a waiver of a requirement that has been waived for other similarly situated utilities in the State of Indiana. We have approved similar waivers for CEI South in Cause No.

45990, Duke in Cause No. 45253, Indiana Michigan Power Company in Cause No. 45567, and AES Indiana in Cause No. 45911.

Based on the evidence of record, we find that NIPSCO's ARP to provide a waiver of the requirement of an on-site premises visit prior to disconnection, as proposed and modified on rebuttal, is in the public interest and approve it. NIPSCO shall pursue the three-month customer communication plan outlined in Ms. Whitehead's direct testimony, with the additional OUCC-recommended communication methods and language as agreed to in Ms. Whitehead's rebuttal and agreed to by the Settling Parties in Section B.14. of the Settlement Agreement.

C. Ultimate Findings on Settlement. Based on the evidence presented, we find nothing presented by the CAC in its settlement opposition evidence causes the Commission to find the Settlement should be modified or rejected. While the Settlement did not result in an outcome that perfectly aligns with the CAC's litigated position, the same can be said for all parties to this Cause. Nevertheless, the Settlement Agreement does reasonably address the revenue, cost allocation, and rate design matters in the context of all parties' litigated positions, including the CAC.

The Settlement Agreement results in a reasonable revenue increase, which reflects a fair return of and on capital investment made by NIPSCO if the utility is operated efficiently and enables NIPSCO to continue to provide reliable service to its customers on a sound financial foundation. The evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is within the range of potential outcomes and represents a fair resolution of the issues presented within the guardrails of the Five Pillars. Accordingly, based on the evidence presented, we find that the Settlement Agreement is reasonable, supported by substantial evidence, in the public interest and is approved without modification.

The revenue allocation shall be as set forth in the Settlement and Petitioner's Exhibit 16-S, Attachment 16-S-A. This revenue allocation is based upon the projected rate base and capital structure; the actual revenue allocation shall be based upon the actual rate base, and capital structure at the time, following the multiple-step mitigation process set forth in the Settlement. We find that based upon the projected capital structure and rate base, the rates set forth in Attachment 16-S-B and the tracker allocations set forth in Attachment 16-S-D of Petitioner's Exhibit 16-S, are reasonable and should be approved. We further find that the depreciation accrual rates set forth in Joint Exhibit B to the Settlement Agreement should be approved.

NIPSCO shall be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $257,043,752, total base rate revenue of $2,086,642,669, and total net operating income of $651,868,680. This is based upon Forward Test Year ending net original cost rate base of $9,129,813,441 as follows:

Net Utility Plant	$7,396,151,653
Schahfer Units 14, 15, 17, and 18 Retirement	$661,125,225
WAM – Regulatory Asset	$28,237,008
Renewable Energy Joint Venture Investments	$772,866,616
Cause Nos. 45772 & 45159 Remainder	$24,524,961
Electric TDSIC Cause Nos. 44733 and 45557	$18,679,396
Wholly Owned Solar Farms – Regulatory Asset	$99,839,760
Materials & Supplies	$112,720,299
Production Fuel	$15,668,523
Original Cost Rate Base	**$9,129,813,441**

We further find that a fair return should be authorized based upon this net original cost rate base and a projected weighted average cost of capital of 7.14%, as follows:

	Total Company Capitalization	Cost %	Weighted Average Cost %
Common Equity	$7,718,129,223	9.75%	5.17%
Long-Term Debt	$5,468,979,284	5.20%	1.95%
Customer Deposits	$59,885,295	5.63%	0.02%
Deferred Income Taxes	$1,691,723,532	0.00%	0.00%
Post-Retirement Liability	($7,491,885)	0.00%	0.00%
Prepaid Pension Asset	($372,308,313)	0.00%	0.00%
Post-1970 ITC	$174,612	7.87%	0.00%
Totals	**$14,559,091,748**		**7.14%**

We further find that NIPSCO shall be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $257,043,752, total base rate revenue of $2,086,642,669, and total net operating income of $651,868,680 as follows:

Original Cost Rate Base	$ 9,129,813,441
Times: Weighted Average Cost of Capital	7.14%
Net Operating Income	$651,868,680
Less: Pro forma Net Operating Income	$ 418,038,218
Net Revenue Increase Required	$ 233,830,462
Gross Revenue Conversion Factor	1.336175
Recommended Gross Revenue Increase Required	$313,139,816
Less: NOI Neutral Revenue Requirement Associated with Fuel Reduction	$56,096,064
Petitioner's Total Recommended Revenue Increase Required	$257,043,752
Recommended Percentage Increase over Revenues Subject to Increase at Present Rates	14.05%

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

(a) Step 1 Rates Subject to Refund: Step 1 rates shall be implemented on a services rendered basis as soon as possible following the issuance of this Order and approval of NIPSCO's new tariffs by the Commission's Energy Division and will be based on actual net plant certified to have been completed and placed in service no later than May 31, 2025, except for the Fairbanks and Gibson solar projects, which may be placed in service later, as set forth herein. Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of May 31, 2025. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of May 31, 2025, and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission under this Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of May 31, 2025. NIPSCO will serve all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. All parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of May 31, 2025, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 Rates Subject to Refund: Step 2 rates shall be implemented on a services rendered basis as soon as possible after the end of the Forward Test Year and will be based on actual net plant certified to have been completed and placed in service no later than December 31, 2025. Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2025. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2025 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission under this Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2025. NIPSCO will serve all parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have 60 days to verify or state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) Additional Interim Phases: In the event Fairbanks and/or Gibson are not in service by the general rate base cutoff for Step 1 (May 31, 2025) but come into service on or before the general rate base cutoff for Step 2 (December 31, 2025), up to two additional steps may occur to include these projects in rates earlier than Step 2 (end of the Forward Test Year). The compliance filing(s) for the additional step(s) will be based on the addition to rate base and associated

depreciation expense for Fairbanks or Gibson (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification under this Cause that the asset is in service and serve a copy of such certification upon all parties to this Cause. The rates will be implemented on a services rendered basis and take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections and for a hearing to potentially be conducted. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in Step 1 rates calculated as provided in this paragraph, subject to potential objections, true-up, and all other matters described above with respect to Step 1 rates.

D. Five Pillars. Through Ind. Code § 8-1-2-0.6, the Indiana General Assembly declared it is the continuing policy of the state that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the Five Pillars of electric utility service: reliability, affordability, resiliency, stability, and environmental sustainability. As such, the Five Pillars have served as the lens through which the Commission has viewed all parties' requested relief in this Cause, including the Settlement Agreement. Per the Legislature's directive, we have considered and evaluated each of the Five Pillars in making our determinations in this case, and our considerations are discussed throughout the findings set forth above.

We find that our approval of the Settlement Agreement properly addresses utility service affordability for present and future generations and balances the Five Pillars. The Settlement Agreement reduces the requested overall revenue requirement, which supports affordability while allowing NIPSCO to maintain its system reliability, resiliency and stability. A significant portion of NIPSCO's requested revenue increase in this case is driven by preapproved projects and TDSIC projects, which contribute to NIPSCO's reliability, resiliency, stability, and environmental sustainability. The Settlement Agreement also furthers NIPSCO's generation transition, which supports environmental sustainability. It also provides additional options for low-income customers, supporting affordability for all customers.

E. Other Matters. The Settlement includes two Addendums that do not require Commission approval because they have no impact on NIPSCO's rates established in this Cause. While we need not approve the Addendums, we note that based on the evidence presented, the terms reasonably address concerns raised by the RV Group and LaPorte County.

In addition, while not part of the Settlement, we note that NIPSCO also committed to assembling a collaborative of educational institutions in response to the numerous comments offered by school districts regarding the challenges presented by electric rate increases. Pet. Ex. 21. NIPSCO committed to providing these entities with information about opportunities to participate in the NIPSCO demand side management oversight board and current program offerings or proposals for new program opportunities from which educational institutions may benefit.

11. Effect of Settlement Agreement. The parties agree that the Settlement Agreement is not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce its terms; consequently, with regard to future citation of the

Settlement Agreement or of this Order, the Commission finds our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, (IURC March 19, 1997).

12. Confidentiality. NIPSCO filed motions for protection and nondisclosure of confidential and proprietary information on September 12, 2024, and January 29, 2025, both of which were supported by affidavits showing certain documents to be submitted to the Commission contain trade secrets as defined under Ind. Code § 23-2-3-2. A docket entry was issued on each motion finding such information to preliminarily be confidential, after which the information was submitted under seal. The Commission finds all such information preliminarily granted confidential treatment is confidential under Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana Law and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. The Settlement Agreement, a copy of which is attached to this Order, is approved.

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

3. New depreciation rates applicable to NIPSCO's common and electric plant are approved as set forth in this Order.

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

5. Petitioner shall certify its net plant, original cost rate base, and capital structure at May 31, 2025 (Step 1) and December 31, 2025 (Step 2) and calculate the resulting rates and charges, which shall be made effective upon filing in accordance with the findings herein, subject to being contested and trued-up consistent with the Settlement Agreement.

6. To the extent that either Fairbanks or Gibson is not completely in service as of May 31, 2025 but is in service before December 31, 2025, Petitioner is authorized to implement up to two additional interim phases to its increase, based upon the Step 1 capital structure as described in Finding Paragraph 10.C. above. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in the calculation of Step 1 rates as provided in this Order.

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

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

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

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

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

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

APPROVED:

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

_____ on behalf of
Dana Kosco
Secretary of the Commission

OFFICIAL
EXHIBITS

IURC JOINT - Settling Parties
EXHIBIT No. 1
3-25-25 AT
REPORTER

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING, BUT LIMITED TO, AUTHORITY TO CAPITALIZE AS RATE BASE ALL EXPENDITURES FOR IMPROVEMENTS TO PETITIONER'S INFORMATION TECHNOLOGY SYSTEMS THROUGH THE DESIGN, DEVELOPMENT, AND IMPLEMENTATION OF A WORK AND ASSET MANAGEMENT ("WAM") PROGRAM, TO THE EXTENT NECESSARY; AND (5) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE PARTIAL WAIVER OF 170 IAC 4-1-16(f) AND PROPOSED REMOTE DISCONNECTION AND RECONNECTION PROCESS AND, TO THE EXTENT NECESSARY, IMPLEMENTATION OF A LOW INCOME PROGRAM.	CAUSE NO. 46120

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of this 7th day of February, 2025, by and among Northern Indiana Public Service Company LLC ("NIPSCO"), the Indiana Office of Utility Consumer Counselor ("OUCC"),

NIPSCO Industrial Group ("Industrial Group"),[1] NLMK Indiana, United States Steel Corporation ("US Steel"), Walmart Inc. ("Walmart"), and RV Industry User's Group ("RV Group") (collectively the "Settling Parties").[2] The Settling Parties, solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth below represent a fair and reasonable resolution of the issues in this Cause subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to each of the Settling Parties regarding the issues resolved herein. In particular, the Settling Parties agree that the rate design and cost allocation methodology set forth in the Settlement Agreement and supporting testimony was a material inducement to entering into the settlement, and a modification of those terms could materially change the benefit of the Settling Parties' bargain. The Settling Parties agree this Agreement resolves all disputes, claims, and issues arising from the electric general rate case proceeding currently pending in Cause No. 46120 as among the Settling Parties. The Settling Parties agree that matters for which NIPSCO requested relief in this Cause that are not addressed herein, but were expressly supported by testimony, are resolved as NIPSCO proposed, or if modified in rebuttal, as modified in

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

2 The Board of County Commissioners of LaPorte County ("LaPorte County"), and United Steel, Paper and Forestry, Rubber Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12755 and 13796 ("USW"), agreed to not oppose. LaPorte County and USW reserve their rights to respond to testimony opposing the Agreement.

rebuttal without waiving the right to challenge such resolution prospectively except as facts and circumstances may allow.

A. Background[3]

1. NIPSCO's Current Basic Rates and Charges. NIPSCO's current electric basic rates and charges were approved pursuant to the Commission's August 2, 2023, Order in Cause No. 45772 (the "45772 Rate Case Order"), wherein the Commission approved a Stipulation and Settlement Agreement, including a Stipulation and Settlement Agreement between NIPSCO and its industrial customers on Rate 831/531 implementation (the "Rate 831/531 Modification Settlement").[4]

2. NIPSCO's Current Depreciation Accrual Rates. NIPSCO's current common and electric depreciation rates were approved in the 45772 Rate Case Order.

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

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[3] This "Background" section is included to provide context for the Agreement and does not reflect any term of the Settling Parties' agreement.

[4] The Rate 831/531 Modification Settlement was entered into on September 12, 2022 by and between NIPSCO, Cleveland-Cliffs Steel LLC, Linde, Inc., BP Products North America, Inc., Cargill, Inc., NLMK Indiana, Pratt Paper (IN), LLC, and US Steel.

4. This Proceeding. On September 12, 2024, NIPSCO filed its Verified Petition with the Commission requesting the Commission issue an order: (1) authorizing NIPSCO to modify its retail rates and charges for electric utility service through the phase-in of rates; (2) approving new schedules of rates and charges, general rules and regulations, and riders; (3) approving revised common and electric depreciation rates applicable to its electric plant in service; (4) approving necessary and appropriate accounting relief, including, but not limited to, authority, to the extent necessary, to capitalize as rate base all expenditures for improvements to Petitioner's information technology systems through the design, development, and implementation of the WAM program;[5] (5) approving an alternative regulatory plan for a partial waiver of the requirements of 170 IAC 4-1-16(f); (6) approval of a new low income program, including through an alternative regulatory plan if necessary; (7) authorizing NIPSCO to implement temporary rates; and (8) approving other requests as described in the Verified Petition. NIPSCO filed its case-in-chief testimony and exhibits on September 12, 2024. On December 19, 2024, the OUCC and intervenors filed their respective cases-in-chief. On January 16, 2025, NIPSCO filed its rebuttal testimony and exhibits, and the OUCC, CAC, Industrial Group, US Steel, NLMK, and RV Group filed cross-answering testimony and exhibits.

[5] The same request had been made in Cause No. 46025. The relief sought in that Cause was unopposed, but the request remained pending as of the filing of NIPSCO's Verified Petition. The Commission approved NIPSCO's request in its September 25, 2024 Order in Cause No. 46025.

As discussed within NIPSCO's Verified Petition and the testimony of various parties including NIPSCO, since the 45772 Rate Case Order, NIPSCO has brought one (1) solar facility online (Cavalry Solar Plus Storage) and anticipates three (3) solar facilities (Dunn's Bridge II Solar Plus Storage, Fairbanks Solar, and Gibson Solar) to come online by the end of the Forward Test Year.[6] NIPSCO also plans to retire Schahfer Generating Station Units 17 and 18 by the end of the Forward Test Year. NIPSCO seeks to change its rates to reflect the effects, including benefits, of these projects and retirements. Since the end of the test year in Cause No. 45772 and the end of the Forward Test Year in this case, NIPSCO projects its net original cost rate base will grow by nearly $3 billion.

NIPSCO seeks to revise its existing rates to address the changing energy marketplace, NIPSCO's generation transition, and to provide revenues adequate to cover its necessary and reasonable operating expenses and permit NIPSCO to earn a fair return upon the fair value of its property. NIPSCO's supporting evidence in this Cause indicates that revisions to NIPSCO's rates are sought to afford NIPSCO an

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[6] Dunn's Bridge II Solar Plus Storage (originally approved in Cause No. 45462, modification approving wholly owned structure in Cause No. 45936) has an aggregate nameplate capacity of approximately 435 MW solar plus 75 MW energy storage. NIPSCO anticipates receiving power in Quarter 1, 2025 and is included in rate base in this proceeding. Fairbanks Solar (originally approved in Cause No. 45511, modification approving wholly owned structure in Cause No. 46028) has an aggregate nameplate capacity of approximately 250 MW. NIPSCO anticipates receiving power in Quarter 2, 2025 and is included in rate base in this proceeding. Gibson Solar (originally approved in Cause No. 45926, modification approving wholly owned structure in Cause No. 46032) has an aggregate nameplate capacity of approximately 200 MW. NIPSCO anticipates receiving power from this facility in Quarter 3, 2025 and is included in rate base in this proceeding.

opportunity to recover its operating expenses and earn a fair return on the fair value of its property used and useful in providing service to its customers. NIPSCO further believes that the proposed rate changes will also enable NIPSCO to attract capital required for additions, replacements, and improvements to its Utility Property and to comply with regulatory mandates and otherwise provide adequate and reliable service. Intervenors took issue with multiple aspects of the NIPSCO rate filing in their responsive testimony.

B. Settlement Terms

1. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement. The Settling Parties agree that NIPSCO's Step 2 base rates will be designed to produce revenue at proposed rates of $2,086,642,669 prior to application of surviving Riders.[7] This Revenue Requirement represents an increase of $257,043,752 from current rates. The agreed upon Revenue Requirement amounts to a reduction of $111,616,865 (30.28%) from the revenue requirement NIPSCO requested in its case-in-chief ($2,198,259,534). The Settling Parties agree the settlement Revenue Requirement reflects the depreciation study and accrual rates and amortization as discussed below. Joint Exhibit A attached hereto represents

[7] In this Agreement, as described in Section 10(b) below, "Step 2" shall refer to the ultimate step of rate implementation based upon the end of the Forward Test Year, even though as set forth herein, there could be more than two steps to the increase.

the schedules supporting the calculation of the agreed settlement Revenue Requirement based on the 12-month period ending December 31, 2025.

(b) Net Operating Income. The Settling Parties agree that the settlement Revenue Requirement in Paragraph B.1(a) above results in a proposed authorized net operating income of $651,868,680.

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

(a) Original Cost Rate Base. NIPSCO agrees its weighted average cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this Agreement, the Settling Parties agree NIPSCO should be authorized a fair rate of return of 7.14%, yielding an overall return for earnings test purposes of $651,868,680, based upon: (a) a Net Original Cost Rate Base of $9,129,813,441; and (b) NIPSCO's forecasted capital structure, including an authorized return on equity ("ROE") of 9.75%.

(b) Capital Structure and Fair Return. Based on the following capital structure, the 9.75% ROE, and the cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	Dollars	**Cost %**	**WACC %**
Common Equity	$7,718,129,223	9.75%	5.17%
Long-Term Debt	$5,468,979,284	5.20%	1.95%
Customer Deposits	$59,885,295	5.63%	0.02%
Deferred Income Taxes	$1,691,723,532	0.00%	0.00%

Post-Retirement Liability	$(7,491,885)	0.00%	0.00%
Prepaid Pension Asset	$(372,308,313)	0.00%	0.00%
Post-1970 ITC	$174,612	7.87%	0.00%
Totals	**$14,559,091,748**		**7.14%**

The Settling Parties agree that fair return under the Agreement will be calculated based upon the actual capital structure and rate base as described in the Implementation of Rates set forth in Paragraph B.10.

3. Depreciation and Amortization Expense.

(a) Depreciation Expense. The Settling Parties agree to a $12,270,000 reduction to NIPSCO's proposed depreciation expense. This amount is comprised of a $10,000,000 reduction as a result of reducing decommissioning costs and adjusting originally proposed service lives or net salvage components associated with certain depreciation accrual rates; and a $2,270,000 reduction as a result of the $100,000,000 reduction to NIPSCO's case-in-chief forecasted Transmission & Distribution Rate Base. The resulting depreciation accrual rates to which the Settling Parties agree are shown in Joint Exhibit B attached to this Agreement

(b) Amortization Expense. The Settling Parties agree to a $5,556,445 reduction to NIPSCO's proposed amortization expense achieved by modifying the amortization periods for TDSIC and Electric Rate Case Expense regulatory asset balances from two to four years. NIPSCO shall make a compliance filing at the

conclusion of all amortization periods as each concludes to remove the amortization from the revenue requirement, and rates will be adjusted accordingly.

4. Pro Forma Net Operating Income at Present Rates.

(a) Fuel Costs. The Settling Parties agree the base cost of fuel proposed in NIPSCO's case-in-chief will be reduced by $8,970,840.

(b) O&M Expenses. The Settling Parties agree to a $20,000,000 reduction to total O&M in this case. This reduction is a compromise to resolve numerous disputed issues in this Cause, including NIPSCO labor vacancies (generation and non-generation related), NiSource Corporate Service Company (NCSC) labor vacancies, vegetation management expense, and certain estimated costs incurred to execute NIPSCO's rate case.

5. Bill Assistance Program. The Settling Parties recommend approval of NIPSCO's request for approval of a bill assistance program (Rider 697 – Universal Service Program Rider) with the following changes:

(a) In recognition of concerns expressed by the OUCC, NIPSCO agrees to modify the bill assistance program from an opt-out program as proposed in NIPSCO's rebuttal to a voluntary, opt-in program; and

(b) In recognition of concerns expressed by the Settling Parties, NIPSCO will make an annual, below the line (*i.e.*, not to be recovered through rates) shareholder contribution of $1,500,000.

6. Customer Deposit. The Settling Parties agree to a reduction of NIPSCO's customer deposit from $50 to $0 for all NIPSCO gas and electric customers who receive bill assistance through LIHEAP.

7. Reconnection Charge. For NIPSCO's electric customers who are disconnected for non-payment of charges, NIPSCO agrees to waive its $90 electric reconnection charge (at the meter during normal business hours) set out in Section 15.1.1 of its General Rules and Regulations no later than with the implementation of Step 2 rates.

8. Disconnection Procedure. NIPSCO agrees to delay disconnection for non-payment of electric service if temperatures are below 20 degrees or above 90 degrees on the scheduled day of disconnection or are forecasted to be below 20 degrees or above 90 degrees the following two days.

9. Public Facing Electric Vehicle ("EV") Rate. NIPSCO commits to a stakeholder process within six (6) months of the date of the Final Order in this Cause with the intent of incorporating a public-facing EV rate to facilitate charging at customer-owned locations in NIPSCO's next electric base rate case.

10. Implementation of Rates. The Settling Parties agree the rate changes will be implemented on a services rendered basis after NIPSCO's new tariffs have been approved by the Commission's Energy Division. The rate increase agreed to herein should be implemented in multiple steps, as follows:

(a) Step 1 rates shall be implemented on a services rendered basis as soon as possible following the issuance of an Order in this Cause and approval of NIPSCO's new tariffs by the Commission's Energy Division and will be based on actual net plant certified to have been completed and placed in service no later than May 31, 2025, except for Fairbanks Solar Generating Facility ("Fairbanks") and Gibson Solar Generating Facility ("Gibson) as set forth herein. The Settling Parties agree that Step 1 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of May 31, 2025. Prior to implementation of Step 1 rates, NIPSCO will certify the net original cost rate base and current capital structure as of May 31, 2025, and calculate the Step 1 rates using those certified figures. For purposes of Step 1 rates, "certify" means NIPSCO states in a filing with the Commission in the above-captioned Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of May 31, 2025. NIPSCO will serve all Parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have sixty (60) days to verify or

state any objection to the net plant in service numbers from those which NIPSCO certifies. All Parties to this proceeding shall be permitted to conduct discovery to verify relevant construction costs and in service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual net plant in service as of May 31, 2025, and rates will be trued up, with carrying charges, retroactive to the date Step 1 rates were put into place.

(b) Step 2 rates shall be implemented on a services rendered basis as soon as possible after the end of the Forward Test Year and will be based on actual net plant certified to have been completed and placed in service no later than December 31, 2025. The Settling Parties agree that Step 2 rates are subject to refund in the event the Commission determines that less than the certified amount of plant additions were placed in service as of December 31, 2025. Prior to implementation of Step 2 rates, NIPSCO will certify the net original cost rate base and current capital structure as of December 31, 2025 and calculate the Step 2 rates using those certified figures. For purposes of Step 2 rates, "certify" means NIPSCO states in a filing with the Commission in the above-referenced Cause the amount of forecasted net plant it has completed and verifies that those forecasted additions have been placed in service and are used and useful in providing utility service as of December 31, 2025. NIPSCO will serve all Parties to this proceeding with its certification. The Settling Parties, and other interested parties to this proceeding, will thereafter have sixty (60) days to verify or

state any objection to the net plant in service numbers from those which NIPSCO certifies. The Settling Parties shall be permitted to conduct discovery to verify relevant construction costs and service dates. If any objections are stated, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued up, with carrying charges, retroactive to the date Step 2 rates were put into place.

(c) In the event NIPSCO's Fairbanks and/or Gibson are not in service by the general rate base cutoff for Step 1 (May 31, 2025) but come into service on or before the general rate base cutoff for Step 2 (December 31, 2025), the Settling Parties agree to up to two additional steps to include these projects in rates earlier than Step 2 (end of the Forward Test Year). The compliance filing(s) for the additional step(s) will be based on the addition to rate base and associated depreciation expense for Fairbanks or Gibson (whichever the case may be) upon the filing of a certification that the plant is in service. The rates will use the capital structure used for Step 1 rates. NIPSCO shall file a certification in the above-captioned Cause that the asset is in service and serve a copy of such certification upon all Parties to this Cause. The rates will take effect on the same interim-subject-to-refund basis as Step 1 and Step 2 rates, with the same period for other parties to raise objections and for a hearing to potentially be conducted. To the extent Fairbanks and/or Gibson are not in service by May 31, 2025, but are in service by the time of the Step 1 compliance filing in this Cause, NIPSCO may include the plant in Step 1 rates calculated as provided in this paragraph, subject to potential objections,

true-up, and all other matters described in Section 10(a) above with respect to Step 1 rates.

11. Cost of Service and Rate Design. The provisions of the 831/531 Modification Settlement and Section B.7.(e) through (g) of the Settlement Agreement approved in Cause No. 45772 continue to apply.

(a) Mitigation. The Settling Parties acknowledge that, as presented in NIPSCO's case-in-chief and rebuttal, certain rate classes are being subsidized by several other rate classes. For this reason, the Settling Parties have agreed to mitigate a portion of the subsidy concerns raised by multiple parties in this Cause consistent with similar concerns recognized in and dealt with in Section B.7.b. of the Settlement Agreement approved in Cause No. 45772, which incorporates and recognizes the Commission's policy of gradualism. The settlement revenue requirement reduction (*i.e.*, the settled annual revenue requirement below NIPSCO's as-filed case in chief) in this Cause will be apportioned as follows: (1) set revenues for Rate 631 at cost of service based on 162.061 megawatts ("MW") of allocated Tier 1 demand; (2) no revenue change to Rate 642 and Rate 643; (3) credit $575,000 of the settlement revenue requirement decrease first to each Rate 623 and Rate 626; (4) allocate 25% of the remaining settlement revenue requirement decrease to the subsidizing classes in proportion to their excess revenues ("25% portion"); and (5) the remaining amount allocated on an across-the-board basis in

proportion to the case-in-chief proposed revenues (75% portion). Because Rate 631 is being brought to parity at 162.061 MW of allocated demand, it will not receive either a reduction relating to the 25% portion or a reduction related to the 75% portion, nor will Rate 642 and Rate 643 as there is no change in revenues for those rate classes. Rate 611 will participate in the across-the-board reduction (the 75% portion).[8] The provisions of this paragraph will be implemented in the cost of service study and rates included with NIPSCO's testimony supporting this Agreement.

(b) Production and Distribution Classification and Allocation in Future Cases. In light of issues raised by the OUCC, Industrial Group, U.S. Steel, and CAC, NIPSCO will study its production, transmission, and distribution classification and allocation before filing its next general electric rate case. This will include studying the classification and allocation of production, transmission (including subfunctionalization by voltage), and distribution customer, demand, and energy related costs both in base rates as well as in the FAC and RA trackers. If, based on that study, NIPSCO subsequently proposes new methods for the classification and allocation of production, transmission, and distribution costs in its next general rate case, it will file testimony explaining and substantiating each of those changes. If NIPSCO does not adopt any such changes, it will similarly file testimony providing the results of its analysis demonstrating why NIPSCO has concluded the current approach remains appropriate.

[8] As further provided below, Rate 611 will be NIPSCO's only residential rate, as the proposed Rate 615 will not be adopted under the terms of this Agreement.

All Settling Parties retain all rights in future proceedings to take any position and litigate these issues.

(c) Reductions in Tier 1 Load and Cost Allocations. The Settling Parties agree that a method for future reduction in Rate 631 Tier 1 allocated and contract demand provided for in the 831/531 Modification Settlement is accomplished through the approach recommended by Industrial Group Witness Dauphinais (Direct at 22-23), with the exclusion of costs associated with Sugar Creek Generating Station, as recommended by U.S. Steel Witness Schuepbach in cross-answering testimony (at 7). Using this approach, the allocated Rate 631 Tier 1 demand shall be 162.061 MW. Mr. Dauphinais' recommendation (Direct at 24-25) of proportional reductions to Rate 631 Tier 1 contract demand to progressively narrow the disparity between Rate 631 allocated demand and class contract demand in order to move the rate toward the actual cost of service should also be approved. The contract demand assumed for purposes of this Agreement shall be 153.692 MW. The Rate 631 charges (transmission, energy, and demand) will be based upon the 153.692 MW of contract demand assumed for purposes of this Agreement as reflected in Confidential Joint Exhibit C, which is expected to be consistent with executed Rate 631 contracts. Future reductions to Rate 631 Tier 1 cost allocations shall continue to follow the methodology set forth in Paragraph 7(f) of the Stipulation and Settlement Agreement approved by the

Commission in Cause No. 45772 employing the computational methodology utilized in this Agreement.

(d) Rate 626. The settlement revenue requirement decrease allocated to Rate 626 will be applied 50% to Rate 626's demand charge and 50% to its energy charge.

(e) Customer Charges. Customer charges proposed by NIPSCO in its case-in-chief shall be approved, except NIPSCO's monthly customer charge for Rate 611 shall remain at $14.00.

12. Data Center Sub-docket. Certain parties in this Cause have requested the creation of a sub-docket for purposes of developing a standard tariff offering and addressing other pertinent issues related to new large or mega load customers that may locate in NIPSCO's electric service territory. Since the filing of NIPSCO's case-in-chief and the OUCC's and intervenors' cases-in-chief, NIPSCO has made a filing related to its proposed overall strategy to serve large or mega load customers, in which NIPSCO acknowledged that it has not entered into any special contract or equivalent agreement for energy services for a large or mega load customer. NIPSCO's intention is that any large or mega load customer that may enter into a contract for electric service will commit to pay the direct, incremental costs associated with serving their load and some portion of the costs of NIPSCO's existing electric system. To the extent NIPSCO enters into such contract(s), NIPSCO commits to timely file a proposal with the Commission to

timely pass back to NIPSCO's current electric customers the revenues NIPSCO collects related to payment for recovery of some portion of the costs of NIPSCO's existing electric system paid by the large or mega load customer(s). This settlement provision in no way waives or otherwise limits any argument a party may make in pending Cause No. 46183 or related dockets surrounding large or mega load customers, except NIPSCO shall be precluded from requesting that any portion of the revenues identified above not be passed to NIPSCO's then current electric customers.

13. Multi-Family Rate. The Settling Parties agree NIPSCO's requested multi-family rate shall not be implemented. NIPSCO will collect additional data on residential customer housing types to further identify multi-family customers and further analyze cost differentials between single- and multi-family residential customers. NIPSCO may consider requesting a new multi-family rate for qualifying residential customers in its next rate case. Once additional analysis is complete, NIPSCO will meet with CAC, the OUCC, and any other interested stakeholders prior to filing its next base rate case to discuss a potential multi-family rate and will provide CAC, the OUCC, and any other interested stakeholders with the results of its analysis.

14. LaPorte County. LaPorte County is agreeing to not oppose this Agreement for the consideration and commitments contained in Addendum A, which NIPSCO agrees to support, but which other Settling Parties will not oppose.

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

16. Other Relief Requested by NIPSCO. The Settling Parties agree that all other matters for which NIPSCO requested relief in this Cause that are not addressed herein, but NIPSCO expressly supported by testimony, should be approved as NIPSCO proposed, or, if modified in NIPSCO's rebuttal, consistent with such modification, without waiving the right to challenge such resolution prospectively.

C. Procedural Aspects and Presentation of the Agreement

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

2. The Settling Parties agree to jointly present this Agreement to the Commission for approval in this proceeding and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval. All evidence which has been prefiled by

the Settling Parties will be admitted into the record. All Settling Parties waive cross-examination on all witnesses of other Settling Parties but reserve the right to ask questions of any witness who may be cross-examined by a non- settling party.

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

4. The Settling Parties acknowledge that this Agreement addresses all issues in the proceeding, including the appropriate revenue requirement and allocation of costs, and includes compromises upon the part of each Settling Party. The Settling Parties agree that this Agreement and each term, condition, amount, methodology, and exclusion contained herein (a) reflects a fair, just, and reasonable resolution and compromise for the purpose of settlement; (b) has accounted for the overall level of risk

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

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

6. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby; and further represent and agree that each Settling Party has had the opportunity to

review all evidence in this proceeding, consult with attorneys and experts, and is otherwise fully advised of the terms.

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

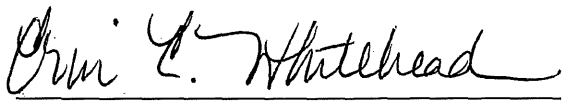
8. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

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

ACCEPTED AND AGREED this 7th day of February, 2025.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC



Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Indiana Office of Utility Consumer Counselor

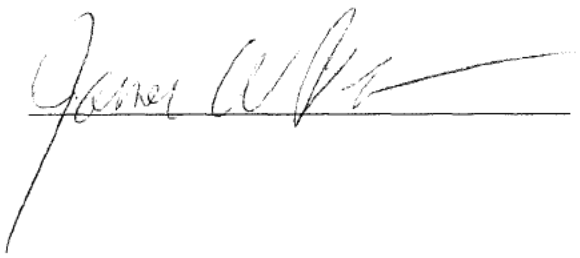


William Fine
Utility Consumer Counselor
Indiana Office of Utility Consumer Counselor
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204

NIPSCO Industrial Group



NLMK Indiana

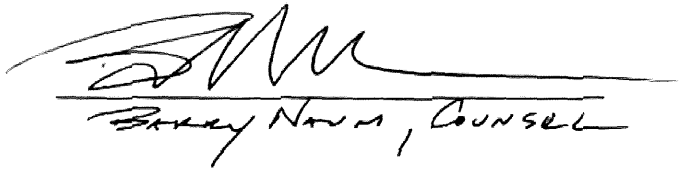


United States Steel Corporation



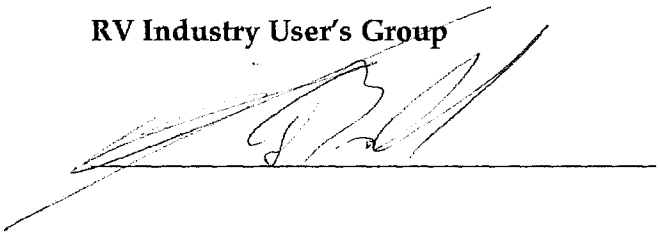
Kristina Kern Wheeler, Counsel for USS

Walmart Inc.



46120

RV Industry User's Group



Northern Indiana Public Service Company LLC
Statement of Operating Income
Actual, Pro forma, and Proposed
For the Twelve Month Period Ending December 31, 2025

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates	Pro forma Adjustments to Include ITC/PTC & IJ17/18 Fuel Reduction	Attachment 3-C Reference	Total Pro forma Adjustments Increases (Decreases)	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J	K	L
1	**Operating Revenue**											
2	Revenue (Actual / Pro Forma)	$ 1,767,958,828		REV, Col A	$ 1,829,598,917	313,139,816	PF - 1 - S2-S	$ 2,142,738,733	(56,096,064)	PF - 5 - S2	257,043,752	$ 2,086,642,669
3	Pro forma Adjustments December 31, 2023		16,183,927	REV, Col B								
4	2024 Year-Over-Year Increase/(Decrease)		172,399,174	REV, Col D								
5	2025 Year-Over-Year Increase/(Decrease)		(16,191,462)	REV, Col F								
6	Ratemaking Adjustments December 31, 2025		(110,761,550)	REV, Col H								
7	Total Operating Revenue	$ 1,767,958,828	$ 61,630,089		$ 1,829,598,917	$ 313,139,816		$ 2,142,738,733	$ (56,096,064)		$ 257,043,752	$ 2,086,642,669
8	**Fuel & Purchased Power**											
9	Fuel and Purchase Power Cost (Actual / Pro Forma)	$ 436,087,415		FPP, Col A	$ 320,663,203	-		$ 320,663,203			(55,755,482)	$ 264,907,721
10	Pro forma Adjustments December 31, 2023		5,184,043	FPP, Col B								
11	2024 Year-Over-Year Increase/(Decrease)		(43,532,296)	FPP, Col D								
12	2025 Year-Over-Year Increase/(Decrease)		(67,201,166)	FPP, Col F								
13	Ratemaking Adjustments December 31, 2025		(8,874,773)	FPP-S, Col H					(55,755,482)	PF - 6 - S2, FPP, Col J		
14	Total Fuel and Purchased Power Costs	$ 436,087,415	$ (114,424,212)		$ 320,663,203	$ -		$ 320,663,203	$ (55,755,482)		$ (55,755,482)	$ 264,907,721
15	Gross Margin	$ 1,332,881,413	$ 176,054,301		$ 1,508,935,713	$ 313,139,816		$ 1,822,075,530	$ (340,582)		$ 312,799,234	$ 1,821,734,948
16	**Operations and Maintenance Expenses**											
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 522,342,734		O&M, Col A	$ 447,401,861	1,431,487	PF - 2 - S2-S	$ 448,833,349	(256,438)	PF - 7 - S2	1,175,050	$ 448,576,911
18	Pro forma Adjustments December 31, 2023		(25,587,605)	O&M, Col B								
19	2024 Year-Over-Year Increase/(Decrease)		21,876,245	O&M, Col D								
20	2025 Year-Over-Year Increase/(Decrease)		12,295,675	O&M, Col F								
21	Ratemaking Adjustments December 31, 2025		(83,527,388)	O&M-S, Col H								
22	Total Operations and Maintenance Expense	$ 522,342,734	$ (74,940,873)		$ 447,401,861	$ 1,431,487		$ 448,833,349	$ (256,438)		$ 1,175,050	$ 448,576,911
23	**Depreciation Expense**											
24	Depreciation Expense (Actual / Pro Forma)	$ 271,619,214		DEPR, Col A	$ 376,764,290			$ 376,764,290			-	$ 376,764,290
25	Pro forma Adjustments December 31, 2023		(2,752,431)	DEPR, Col B								
26	2024 Year-Over-Year Increase/(Decrease)		48,483,292	DEPR, Col D								
27	2025 Year-Over-Year Increase/(Decrease)		66,704,866	DEPR, Col F								
28	Ratemaking Adjustments December 31, 2025		(7,290,652)	DEPR-S, Col H								
29	Total Depreciation Expense	$ 271,619,214	$ 105,145,076		$ 376,764,290	$ -		$ 376,764,290	$ -		$ -	$ 376,764,290

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments	Attachment 3-C Reference	Pro forma Results Based on Proposed Rates	Pro forma Adjustments to Include ITC/PTC & U17/18 Fuel Reduction	Attachment 3-C Reference	Total Pro forma Adjustments Increases (Decreases)	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J	K	L
30	**Amortization Expense**											
31	Amortization Expense (Actual / Pro Forma)	$ 93,159,655		AMTZ, Col A	$ 177,418,026			$ 177,418,026			-	$ 177,418,026
32	Pro forma Adjustments December 31, 2023		15,642,568	AMTZ, Col B								
33	2024 Year-Over-Year Increase/(Decrease)		23,076,164	AMTZ, Col D								
34	2025 Year-Over-Year Increase/(Decrease)		2,818,657	AMTZ, Col F								
35	Ratemaking Adjustments December 31, 2025		42,718,971	AMTZ-S, Col H								
36	Total Amortization Expense	$ 93,159,655	$ 84,258,371		$ 177,418,026	$ -		$ 177,418,026	$ -		$ -	$ 177,418,026
37	**Taxes**											
38	**Taxes Other than Income**											
39	Taxes Other than Income (Actual / Pro Forma)	$ 35,013,168		OTX, Col A	$ 43,310,222			$ 43,310,222			-	$ 43,310,222
40	Pro forma Adjustments December 31, 2023		(195,174)	OTX, Col B								
41	2024 Year-Over-Year Increase/(Decrease)		4,404,074	OTX, Col D								
42	2025 Year-Over-Year Increase/(Decrease)		5,732,803	OTX, Col F								
43	Ratemaking Adjustments December 31, 2025		(1,644,649)	OTX, Col H		469,710	PF - 3 - S2-S	$ 469,710	(84,144)	PF - 8 - S2	365,566	$ 365,566
44	Total Taxes Other Than Income	$ 35,013,168	$ 8,297,054		$ 43,310,222	$ 469,710		$ 43,779,932	$ (84,144)		$ 365,566	$ 43,695,787
45	**Operating Income Before Income Taxes**	$ 410,746,641	$ 53,294,673		$ 464,041,314	$ 311,238,619		$ 775,279,933	$ -		$ 311,238,619	$ 775,279,933
46	**Income Taxes**											
47	Federal and State Taxes (Actual / Pro Forma)	$ 47,253,066	(1,249,990)	~~Attachment 3-C-S~~, ITX 1-S	$ 46,003,096	77,408,157	PF - 4 - S2-S	$ 123,411,253	-	PF - 9 - S2	77,408,157	$ 123,411,253
48	Total Taxes	$ 82,266,254	$ 7,047,064		$ 89,313,318	$ 77,877,867		$ 167,191,185	$ (84,144)		$ 77,793,723	$ 167,107,041
49	**Total Operating Expenses including Income Taxes**	$ 969,387,857	$ 121,505,636		$ 1,090,897,495	$ 79,309,354		$ 1,170,206,849	$ (340,582)		$ 78,958,772	$ 1,169,866,268
50	**Required Net Operating Income**	$ 393,493,556	$ 54,544,662		$ 418,036,217.55000	$ 233,630,462		$ 651,666,680	$ -		$ 233,630,462	$ 651,666,680

Northern Indiana Public Service Company LLC
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2025

Line No.	Description				Revenue Deficiency
1	Net Original Cost Rate Base				$ 9,129,813,441
2	Rate of Return				7.14%
3	Net Operating Income				651,868,680
4	Pro forma Net Operating Income				418,038,218
5	Increase in Net Operating Income (NOI Shortfall)				233,830,462
6	Effective Incremental Revenue NOI Conversion Factor				74.673%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)				$ 313,139,816
8	One	1.000000			
9	Less: Public Utility Fee	0.001500			
10	Less: Bad Debt	0.004571			
11	State Taxable Income		0.993929		
12	Taxable Adjusted Gross Income Tax	0.993929			
13	Adjusted Gross Income Tax Rate	0.049000			
14	Adjusted Gross Income Tax		0.048703		
15	Line 11 less line 14			0.945226	
16	One		1.000000		
17	Less: Federal Income Tax Rate		0.210000		
18	One Less Federal Income Tax Rate			0.790000	
19	Effective Incremental Revenue / NOI Conversion Factor				74.673%

Northern Indiana Public Service Company LLC
Summary of Rate Base
As Of December 31, 2025

Line No.	Description	As Of December 31, 2025	Attachment 3-B-S2-S Reference
	Electric Rate Base		
1	Utility Plant	$ 10,216,836,696	RB, Col I
2	Non Jurisdictional Plant	-	RB, Col I
3	Common Allocated	419,723,256	RB, Col I
	Total Electric Utility Plant	10,636,559,953	RB, Col I
4	Utility Plant Accumulated Depreciation and Amortization	(2,977,780,579)	RB, Col I
5	Non Jurisdictional Plant Accumulated Depreciation and Amortization	-	RB, Col I
6	Common Allocated Accumulated Depreciation and Amortization	(262,627,721)	RB, Col I
	Total Electric Accumulated Depreciation and Amortization	(3,240,408,299)	RB, Col I
	Net Electric Utility Plant	$ 7,396,151,653	RB, Col I
7	Schahfer Units 14, 15, 17 and 18 Retirement Net Plant	661,125,225	RB, Col I
8	WAM Regulatory Asset	28,237,008	RB, Col I
9	Renewable Energy Joint Venture Investments	772,866,616	RB, Col I
10	Cause Nos. 45772 & 45159 Remainder	24,524,961	RB, Col I
11	Electric TDSIC Cause Nos. 44733 and 45557	18,679,396	RB, Col I
12	Wholly Owned Solar Farms - Regulatory Asset	99,839,760	RB, Col I
13	Materials & Supplies	112,720,299	RB, Col I
14	Production Fuel	15,668,523	RB, Col I
	Total Electric Rate Base	**$ 9,129,813,441**	RB, Col I

Northern Indiana Public Service Company LLC
Capital Structure
As Of December 31, 2025

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	$ 7,718,129,223	53.01%	9.75%	5.17%
2	Long-Term Debt	5,468,979,284	37.56%	5.20%	1.95%
3	Customer Deposits	59,885,295	0.41%	5.63%	0.02%
4	Deferred Income Taxes	1,691,723,532	11.62%	0.00%	0.00%
5	Post-Retirement Liability	(7,491,885)	-0.05%	0.00%	0.00%
6	Prepaid Pension Asset	(372,308,313)	-2.56%	0.00%	0.00%
7	Post-1970 ITC	174,612	0.00%	7.87%	0.00%
8	Totals	**$ 14,559,091,748**	**100.00%**		**7.14%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 7,718,129,223	58.53%	9.75%	5.71%
10	Long-Term Debt	5,468,979,284	41.47%	5.20%	2.16%
11	**Totals**	**$ 13,187,108,507**	**100.00%**		**7.87%**

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
STEAM PRODUCTION PLANT									
311.00 STRUCTURES AND IMPROVEMENTS									
MICHIGAN CITY GENERATING STATION	12-2028	110-R2.5 *	(62)	46,027,141.95	19,214,893	55,349,077	6,511,656 **	14.15	8.5
MICHIGAN CITY - UNIT 12	12-2028	110-R2.5 *	(62)	105,391,567.33	51,508,881	119,225,458	14,026,524 **	13.31	8.5
TOTAL MICHIGAN CITY				151,418,709.28	70,723,774	174,574,535	20,538,180	13.56	8.5
SUGAR CREEK	06-2068	110-R2.5 *	(28)	8,084,108.45	4,094,685	6,252,974	152,043	1.88	41.1
TOTAL ACCOUNT 311				159,502,817.73	74,818,459	180,827,509	20,690,223	12.97	
BOILER PLANT EQUIPMENT									
312.10 BOILER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2028	55-R1 *	(62)	90,788,707.47	60,688,863	86,388,843	10,163,393 **	11.19	8.5
MICHIGAN CITY - UNIT 12	12-2028	55-R1 *	(62)	261,925,849.67	166,272,474	258,047,402	30,358,518 **	11.59	8.5
TOTAL MICHIGAN CITY				352,714,557.14	226,961,337	344,436,245	40,521,911	11.49	8.5
SUGAR CREEK	06-2068	55-R1 *	(28)	96,801,493.64	58,392,780	65,513,132	1,914,475	1.98	34.2
TOTAL ACCOUNT 312.1				449,516,050.78	285,354,117	409,949,377	42,436,386	9.44	
312.20 BOILER PLANT - MOBILE FUEL HANDLING AND STORAGE									
MICHIGAN CITY GENERATING STATION	12-2028	55-R1 *	(62)	8,502,659.44	8,356,263	5,418,045	637,417 **	7.50	8.5
MICHIGAN CITY - UNIT 12	12-2028	55-R1 *	(62)	796,688.99	826,154	464,482	54,645 **	6.86	8.5
TOTAL ACCOUNT 312.2				9,299,348.43	9,182,417	5,882,527	692,062	7.44	
312.30 BOILER PLANT - UNIT TRAIN COAL CARS									
MICHIGAN CITY GENERATING STATION		25-R2.5	0	2,841,743.85	2,753,480	88,264	10,384 **	0.37	8.5
312.40 BOILER PLANT - SO2 PLANT EQUIPMENT									
MICHIGAN CITY - UNIT 12	12-2028	55-R1 *	(62)	230,108,218.67	103,181,315	269,593,999	31,716,941 **	13.78	8.5
312.50 BOILER PLANT - COAL PILE BASE									
MICHIGAN CITY GENERATING STATION	12-2028	55-R1 *	(62)	717,113.23	1,197,579	(35,856)	(4,218) **	(0.59)	8.5
TOTAL ACCOUNT 312				692,482,474.96	401,668,908	685,478,311	74,851,555	10.81	
314.00 TURBOGENERATOR UNITS									
MICHIGAN CITY GENERATING STATION	12-2028	60-R2 *	(62)	4,843,911.56	710,782	7,136,355	839,571 **	17.33	8.5
MICHIGAN CITY - UNIT 12	12-2028	60-R2 *	(62)	97,485,934.88	45,078,446	112,848,769	13,276,326 **	13.62	8.5
TOTAL MICHIGAN CITY				102,329,846.44	45,789,228	119,985,124	14,115,897	13.79	8.5
SUGAR CREEK	06-2068	60-R2 *	(28)	57,816,549.33	27,669,122	46,336,061	1,291,945	2.23	35.9
TOTAL ACCOUNT 314				160,146,395.77	73,458,350	166,321,185	15,407,842	9.62	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
315.00 ACCESSORY ELECTRIC EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2028	70-R2 *	(62)	23,807,800.73	25,656,902	12,911,735	1,519,028 **	6.38	8.5
MICHIGAN CITY - UNIT 12	12-2028	70-R2 *	(62)	35,227,102.15	39,953,156	17,114,749	2,013,500 **	5.72	8.5
TOTAL MICHIGAN CITY				59,034,902.88	65,610,058	30,026,484	3,532,528	5.98	8.5
SUGAR CREEK	06-2068	70-R2 *	(28)	4,897,315.43	2,894,694	3,373,870	89,263	1.82	37.8
TOTAL ACCOUNT 315				63,932,218.31	68,504,752	33,400,354	3,621,791	5.67	
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
MICHIGAN CITY GENERATING STATION	12-2028	70-R1.5 *	(62)	3,931,264.86	493,793	5,874,856	691,160 **	17.58	8.5
MICHIGAN CITY - UNIT 12	12-2028	70-R1.5 *	(62)	5,441,982.85	631,322	8,184,690	962,905 **	17.69	8.5
TOTAL MICHIGAN CITY				9,373,247.71	1,125,115	14,059,546	1,654,065	17.65	8.5
SUGAR CREEK	06-2068	70-R1.5 *	(28)	3,563,623.43	1,126,831	3,434,607	91,471	2.57	37.5
TOTAL ACCOUNT 316				12,936,871.14	2,251,946	17,494,153	1,745,536	13.49	
TOTAL STEAM PRODUCTION PLANT				**1,089,000,777.91**	**620,702,415**	**1,083,521,512**	**116,316,947**	**10.68**	
HYDROELECTRIC PRODUCTION PLANT									
331.00 STRUCTURES AND IMPROVEMENTS									
NORWAY GENERATING STATION	11-2037	70-S1 *	(12)	4,615,792.78	1,890,273	3,279,415	278,401	6.03	11.8
OAKDALE GENERATING STATION	11-2037	70-S1 *	(8)	7,173,147.86	3,202,088	4,544,912	386,078	5.38	11.8
TOTAL ACCOUNT 331				11,788,940.64	5,092,361	7,824,327	664,479	5.64	
332.00 RESERVOIRS, DAMS AND WATERWAYS									
NORWAY GENERATING STATION	11-2037	85-R2.5 *	(12)	33,719,831.63	8,970,126	28,796,085	2,438,359	7.23	11.8
OAKDALE GENERATING STATION	11-2037	85-R2.5 *	(8)	37,145,730.66	9,118,796	30,998,593	2,622,088	7.06	11.8
TOTAL ACCOUNT 332				70,865,562.29	18,088,922	59,794,678	5,060,447	7.14	
333.00 WATER WHEELS, TURBINES AND GENERATORS									
NORWAY GENERATING STATION	11-2037	75-R2 *	(12)	7,950,788.80	3,174,832	5,730,051	518,515	6.52	11.1
OAKDALE GENERATING STATION	11-2037	75-R2 *	(8)	6,429,578.26	2,452,118	4,491,827	386,919	6.02	11.6
TOTAL ACCOUNT 333				14,380,367.06	5,626,950	10,221,878	905,434	6.30	
334.00 ACCESSORY ELECTRIC EQUIPMENT									
NORWAY GENERATING STATION	11-2037	55-L1.5 *	(12)	1,678,599.17	1,091,445	788,586	72,478	4.32	10.9
OAKDALE GENERATING STATION	11-2037	55-L1.5 *	(8)	830,241.56	326,461	570,200	49,769	5.99	11.5
TOTAL ACCOUNT 334				2,508,840.73	1,417,906	1,358,786	122,247	4.87	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
335.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
NORWAY GENERATING STATION	11-2037	60-S0.5 *	(12)	1,022,677.29	360,067	785,332	67,846	6.63	11.6
OAKDALE GENERATING STATION	11-2037	60-S0.5 *	(8)	270,873.17	100,425	192,118	16,689	6.16	11.5
TOTAL ACCOUNT 335				1,293,550.46	460,492	977,450	84,535	6.54	
TOTAL HYDROELECTRIC PRODUCTION PLANT				**100,837,261.18**	**30,686,631**	**80,177,119**	**6,837,142**	**6.78**	
OTHER PRODUCTION PLANT									
341.00 STRUCTURES AND IMPROVEMENTS									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-R3 *	(3)	2,484,301.00	1,872,564	686,266	686,264	27.62	1.0
R M SCHAHFER - UNIT 16A	12-2026	55-R3 *	(3)	212,249.57	211,909	6,708	6,708	3.16	1.0
TOTAL R M SCHAHFER				2,696,550.57	2,084,473	692,974	692,972	25.70	1.0
SUGAR CREEK	06-2068	55-R3 *	(17)	13,149,657.86	6,912,218	8,472,882	239,019	1.82	35.4
TOTAL ACCOUNT 341				15,846,208.43	8,996,691	9,165,856	931,991	5.88	
341.10 STRUCTURES AND IMPROVEMENTS - SOLAR		35-S2.5 *	0	49,455.17	3,484	45,971	1,411	2.85	32.6
341.20 STRUCTURES AND IMPROVEMENTS - UTILITY-SCALE SOLAR									
CAVALRY	06-2054	35-R4 *	(16)	54,184,033.32	3,467,681	59,385,798	2,176,899	4.02	27.3
DUNNS BRIDGE II	06-2055	35-R4 *	(9)	105,743,471.58	2,116,878	113,143,506	4,000,831	3.78	28.3
FAIRBANKS	06-2055	35-R4 *	(14)	64,977,969.18	1,361,577	72,713,308	2,571,192	3.96	28.3
GIBSON	06-2055	35-R4 *	(17)	53,506,855.66	1,151,239	61,451,782	2,172,977	4.06	28.3
TOTAL ACCOUNT 341.2				278,412,329.74	8,097,375	306,694,394	10,921,899	3.92	
342.00 FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-S2 *	(3)	9,106,086.70	6,611,384	2,767,885	2,767,887	30.40	1.0
SUGAR CREEK	06-2048	55-S2 *	(17)	3,199,461.54	2,257,626	1,485,744	70,570	2.21	21.1
TOTAL ACCOUNT 342				12,305,548.24	8,869,010	4,253,629	2,838,457	23.07	
343.00 PRIME MOVERS									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-R1 *	(3)	3,850,660.76	1,184,933	2,781,248	2,781,249	72.23	1.0
R M SCHAHFER - UNIT 16A	12-2026	50-R1 *	(3)	15,109,175.53	14,173,710	1,388,741	1,388,740	9.19	1.0
R M SCHAHFER - UNIT 16B	12-2026	50-R1 *	(3)	23,015,175.73	22,726,733	978,898	978,898	4.25	1.0
TOTAL R M SCHAHFER				41,975,012.02	38,085,376	5,148,887	5,148,887	12.27	1.0
SUGAR CREEK	06-2048	50-R1 *	(17)	118,449,540.98	41,169,623	97,416,340	4,735,768	4.00	20.6
TOTAL ACCOUNT 343				160,424,553.00	79,254,999	102,565,227	9,884,655	6.16	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
344.00 GENERATORS										
R M SCHAHFER - UNIT 16A	12-2026	55-R3	*	(3)	5,927,994.17	5,220,374	885,460	885,459	14.94	1.0
R M SCHAHFER - UNIT 16B	12-2026	55-R3	*	(3)	2,723,343.82	2,672,305	132,739	132,740	4.87	1.0
TOTAL R M SCHAHFER					8,651,337.99	7,892,679	1,018,199	1,018,199	11.77	1.0
SUGAR CREEK	06-2048	55-R3	*	(17)	40,450,118.74	25,423,352	21,903,287	1,023,195	2.53	21.4
TOTAL ACCOUNT 344					49,101,456.73	33,316,031	22,921,486	2,041,394	4.16	
344.10 GENERATORS - SOLAR		25-S2.5		0	991,495.17	201,025	790,470	40,046	4.04	19.7
344.20 GENERATORS - UTILITY-SCALE SOLAR										
CAVALRY	06-2054	30-S1.5	*	(16)	277,438,546.57	17,755,358	304,073,356	12,570,209	4.53	24.2
DUNNS BRIDGE II	06-2055	30-S1.5	*	(9)	541,438,377.01	10,839,143	579,328,688	22,998,360	4.25	25.2
FAIRBANKS	06-2055	30-S1.5	*	(14)	332,706,744.45	6,971,750	372,313,939	14,780,228	4.44	25.2
GIBSON	06-2055	30-S1.5	*	(17)	273,971,193.27	5,894,743	314,651,553	12,491,130	4.56	25.2
TOTAL ACCOUNT 344.2					1,425,554,861.30	41,460,994	1,570,367,536	62,839,927	4.41	
345.00 ACCESSORY ELECTRIC EQUIPMENT										
R M SCHAHFER - UNITS 16A AND 16B	12-2026	50-S1	*	(3)	17,562,929.31	9,291,000	8,798,817	8,798,818	50.10	1.0
R M SCHAHFER - UNIT 16A	12-2026	50-S1	*	(3)	1,164,784.62	1,139,694	60,034	60,034	5.15	1.0
R M SCHAHFER - UNIT 16B	12-2026	50-S1	*	(3)	966,720.95	954,635	41,088	41,088	4.25	1.0
TOTAL R M SCHAHFER					19,694,434.88	11,385,329	8,899,939	8,899,940	45.19	1.0
SUGAR CREEK	06-2048	50-S1	*	(17)	34,529,128.11	22,844,101	17,554,979	882,580	2.56	19.9
TOTAL ACCOUNT 345					54,223,562.99	34,229,430	26,454,918	9,782,520	18.04	
345.10 ACCESSORY ELECTRIC EQUIPMENT - SOLAR		25-S2.5		0	247,873.83	50,631	197,243	9,992	4.03	19.7
345.20 ACCESSORY ELECTRIC EQUIPMENT - UTILITY-SCALE SOLAR										
CAVALRY	06-2054	40-R1.5	*	(16)	39,110,279.69	2,502,423	42,865,501	1,684,303	4.31	25.4
DUNNS BRIDGE II	06-2055	40-R1.5	*	(9)	76,326,114.82	1,528,229	81,667,236	3,101,680	4.06	26.3
FAIRBANKS	06-2055	40-R1.5	*	(14)	46,901,391.29	982,959	52,484,627	1,993,339	4.25	26.3
GIBSON	06-2055	40-R1.5	*	(17)	38,621,489.80	831,111	44,356,032	1,684,620	4.36	26.3
TOTAL ACCOUNT 345.2					200,959,275.60	5,844,722	221,373,396	8,463,942	4.21	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
R M SCHAHFER - UNITS 16A AND 16B	12-2026	55-R2 *	(3)	401,558.85	243,846	169,760	169,761	42.28	1.0
R M SCHAHFER - UNIT 16A	12-2026	55-R2 *	(3)	56,008.00	53,824	3,864	3,864	6.90	1.0
TOTAL R M SCHAHFER				457,566.85	297,670	173,624	173,625	37.95	1.0
SUGAR CREEK	06-2048	55-R2 *	(17)	5,637,396.32	3,119,781	3,475,973	165,185	2.93	21.0
TOTAL ACCOUNT 346				6,094,963.17	3,417,451	3,649,597	338,810	5.56	
TOTAL OTHER PRODUCTION PLANT				**2,204,211,583.37**	**223,741,843**	**2,268,479,723**	**108,095,044**	**4.90**	
TRANSMISSION PLANT									
350.20 LAND RIGHTS		80-R4	0	15,667,095.38	11,598,910	4,068,185	52,355	0.33	77.7
352.00 STRUCTURES AND IMPROVEMENTS		70-R1.5	(20)	120,006,206.97	27,822,792	116,184,656	1,905,289	1.59	61.0
353.00 STATION EQUIPMENT		51-S0	(10)	1,209,443,672.94	274,868,958	1,055,519,082	24,320,538	2.01	43.4
354.00 TOWERS AND FIXTURES		75-R3	(30)	234,065,559.12	92,070,828	212,214,399	3,384,642	1.45	62.7
355.00 POLES AND FIXTURES		62-R1	(40)	441,931,660.13	111,011,176	507,693,148	9,090,957	2.06	55.8
356.00 OVERHEAD CONDUCTORS AND DEVICES		70-R2	(40)	316,129,902.23	121,826,202	320,755,661	5,374,212	1.70	59.7
357.00 UNDERGROUND CONDUIT		70-S4	(5)	904,994.78	701,583	248,662	4,599	0.51	54.1
358.00 UNDERGROUND CONDUCTORS AND DEVICES		50-R1.5	(5)	4,441,926.88	1,276,270	3,387,753	80,942	1.82	41.9
359.00 ROADS AND TRAILS		65-R4	0	31,088.94	15,016	16,073	609	1.96	26.4
TOTAL TRANSMISSION PLANT				**2,342,622,107.37**	**641,191,735**	**2,220,087,619**	**44,214,143**	**1.89**	
DISTRIBUTION PLANT									
360.20 LAND RIGHTS		80-R4	0	1,611,388.87	381,082	1,230,307	18,800	1.17	65.4
361.00 STRUCTURES AND IMPROVEMENTS		70-R1.5	(20)	20,834,098.08	9,549,803	15,451,115	276,487	1.33	55.9
362.00 STATION EQUIPMENT		52-S0	(10)	695,297,773.42	169,278,666	595,548,885	13,497,363	1.94	44.1
POLES, TOWERS AND FIXTURES									
364.10 CUSTOMER TRANSFORMER STATION		49-S0	(55)	61,383,975.08	35,822,062	59,323,099	1,491,955	2.43	39.8
364.20 POLES, TOWERS, AND FIXTURES		48-R1	(55)	809,432,020.90	262,404,188	992,215,444	24,161,648	2.99	41.1
TOTAL ACCOUNT 364				870,815,995.98	298,226,250	1,051,538,543	25,653,603	2.95	
365.00 OVERHEAD CONDUCTORS AND DEVICES		65-R1	(65)	503,615,755.75	225,253,840	605,712,157	10,433,512	2.07	58.1
366.00 UNDERGROUND CONDUIT		70-S2.5	(5)	5,754,045.02	2,196,817	3,844,930	77,434	1.35	49.7
367.00 UNDERGROUND CONDUCTORS AND DEVICES		53-R2.5	(35)	719,335,598.55	213,843,036	757,260,022	17,533,397	2.44	43.2
368.00 LINE TRANSFORMERS		47-S0	(10)	438,272,677.07	156,425,125	325,674,820	6,781,818	2.00	37.1
SERVICES									
369.10 OVERHEAD SERVICES		48-R1	(50)	58,862,877.78	42,319,943	45,974,374	1,157,585	1.97	39.7
369.20 UNDERGROUND SERVICES		75-R3	(50)	329,574,657.54	155,332,144	339,029,842	5,315,742	1.61	63.8
TOTAL ACCOUNT 369				388,437,535.32	197,652,087	385,004,216	6,473,327	1.67	

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT		TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)=(8)/(5)	(10)=(7)/(8)
METERS										
370.10 CUSTOMER METERING STATIONS		50-R2	(5)	24,831,212.44	10,772,610	15,300,163	390,624		1.57	39.2
370.20 METERS		25-L0	(5)	129,340,994.65	28,225,729	107,582,315	5,066,122		3.92	21.2
TOTAL ACCOUNT 370				154,172,207.09	38,998,339	122,882,478	5,456,746		3.54	
371.00 INSTALLATIONS ON CUSTOMER PREMISES		20-O1	(30)	13,170,731.71	7,189,523	9,932,428	604,110		4.59	16.4
373.00 STREET LIGHTING AND SIGNAL SYSTEMS		30-L0	(40)	76,079,721.04	23,336,866	83,174,743	3,623,625		4.76	23.0
TOTAL DISTRIBUTION PLANT				**3,887,397,527.90**	**1,342,331,434**	**3,957,254,644**	**92,430,222**		**2.38**	
GENERAL PLANT										
390.00 STRUCTURES AND IMPROVEMENTS		60-R1.5	(10)	80,207,587.38	8,245,613	79,982,733	1,436,514		1.79	55.7
391.10 OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	4,503,477.64	2,826,155	1,677,323	225,067		5.00	7.5
391.20 COMPUTERS AND PERIPHERAL EQUIPMENT		7-SQ	0	10,225,401.21	7,827,834	2,397,567	1,461,186		14.29	1.6
393.00 STORES EQUIPMENT		30-SQ	0	840,983.94	461,876	379,108	28,043		3.33	13.5
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	31,219,333.07	11,811,607	19,407,726	1,249,729		4.00	15.5
395.00 LABORATORY EQUIPMENT		20-SQ	0	5,386,440.92	3,348,174	2,038,267	269,165		5.00	7.6
397.00 COMMUNICATION EQUIPMENT		15-SQ	0	96,126,113.82	26,077,512	70,048,602	6,411,145		6.67	10.9
398.00 MISCELLANEOUS EQUIPMENT		20-SQ	0	5,148,328.91	1,999,319	3,149,010	257,323		5.00	12.2
TOTAL DEPRECIABLE GENERAL PLANT				**233,657,666.89**	**62,598,090**	**179,080,336**	**11,338,172**		**4.85**	
RESERVE ADJUSTMENT FOR AMORTIZATION										
391.10 OFFICE FURNITURE AND EQUIPMENT					125,698		(41,900)	***		3.0
391.20 COMPUTERS AND PERIPHERAL EQUIPMENT					5,847,536		(1,949,179)	***		3.0
393.00 STORES EQUIPMENT					32,579		(10,860)	***		3.0
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT					66,081		(22,027)	***		3.0
395.00 LABORATORY EQUIPMENT					612,538		(204,179)	***		3.0
397.00 COMMUNICATION EQUIPMENT					(2,963,573)		987,857	***		3.0
398.00 MISCELLANEOUS EQUIPMENT					(51,772)		17,258	***		3.0
TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION					**3,669,087**		**(1,223,030)**			
TOTAL DEPRECIABLE ELECTRIC PLANT				**9,857,726,924.62**	**2,924,921,235**	**9,788,600,953**	**378,008,640**		**3.83**	
NONDEPRECIABLE										
302.00 FRANCHISES AND CONSENTS				1,389.41						
303.00 MISCELLANEOUS INTANGIBLE PLANT				243,035,839.45	73,337,609					
310.00 LAND AND LAND RIGHTS				5,192,264.65	(4,007)					
311.00 STRUCTURES AND IMPROVEMENTS										
D H MITCHELL GENERATING STATION				0.00	4,481,692					
312.10 BOILER PLANT EQUIPMENT										
D H MITCHELL GENERATING STATION				0.00	2,821,855					

NORTHERN INDIANA PUBLIC SERVICE COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2025

ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	TOTAL ANNUAL ACCRUAL AMOUNT	TOTAL ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
312.40 BOILER PLANT - SO2 PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION				0.00	6,054				
312.50 BOILER PLANT - COAL PILE BASE									
D H MITCHELL GENERATING STATION				0.00	69,620				
314.00 TURBO-GENERATOR UNITS									
D H MITCHELL GENERATING STATION				0.00	3,298,615				
315.00 ACCESSORY ELECTRIC EQUIPMENT									
D H MITCHELL GENERATING STATION				401.20	(2,570,344)				
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT									
D H MITCHELL GENERATING STATION				0.00	(1,224,757)				
330.00 LAND AND LAND RIGHTS				24,250.62	(98)				
340.10 LAND				18,332,943.61	(14)				
340.20 LAND RIGHTS				76,947,694.40	(4,389)				
350.10 LAND				24,761,238.91	(397,571)				
360.10 LAND				10,426,228.44	(156,718)				
389.10 LAND				16,851.32					
389.20 LAND RIGHTS				101,627.34					
390.20 LEASED PROPERTY				212,673.04	211,320				
ACCOUNTS NOT STUDIED									
TRANSPORTATION EQUIPMENT									
392.10 TRANSPORTATION EQUIPMENT - AUTOS				0.00	(1,030,784)				
392.20 TRANSPORTATION EQUIPMENT - TRAILERS				1,918,863.64	1,148,444				
392.30 TRANSPORTATION EQUIPMENT - TRUCKS < 13,000				367,964.14	(152,667)				
392.40 TRANSPORTATION EQUIPMENT - TRUCKS > 13,000				383,544.66	2,039,666				
396.00 POWER OPERATED EQUIPMENT				5,248,819.05	5,515,650				
MVP ASSETS									
350.10 LAND				1,843,154.51					
350.20 LAND RIGHTS				52,010,326.11	5,006,463				
352.00 STRUCTURES AND IMPROVEMENTS				22,370,048.26	2,999,962				
353.00 STATION EQUIPMENT				164,183,979.14	22,435,835				
354.00 TOWERS AND FIXTURES				42,081,024.55	3,887,635				
355.00 POLES AND FIXTURES				239,684,022.95	48,667,992				
356.00 OVERHEAD CONDUCTORS AND DEVICES				94,066,212.36	14,562,549				
TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED				**1,003,211,361.76**	**184,949,612**				
TOTAL ELECTRIC PLANT				**10,860,938,286.38**	**3,109,870,847**	**9,788,600,953**	**378,008,640**		

* INTERIM SURVIVOR CURVES USED. EACH LOCATION HAS A UNIQUE PROBABLE RETIREMENT DATE.
** ANNUAL ACCRUAL AMOUNT IS BASED ON 8.5-YEAR REMAINING LIFE.
*** SEPARATE RESERVE AMORTIZATION TO BE RECOVERED OVER 5 YEARS BEGINNING IN 2023.

Confidential Joint Exhibit C (Redacted)

Agreed Addendum between NIPSCO and the LaPorte County Commissioners to Not Oppose Settlement Agreement between NIPSCO and OUCC, et al. in Cause No. 46120

1) Michigan City Generating Station – Study

As recommended by LaPorte County Witness Gramarossa, NIPSCO agrees to study the potential of converting the Michigan City Generating Station to a combined cycle gas turbine or gas peaker generating plant or locating battery energy storage systems or other energy technologies at the site of the generating station that would generate local tax revenue for the county and keep good paying jobs in LaPorte County. NIPSCO shall use commercially reasonable efforts to complete this study within six (6) months of the issuance of a final order approving the Stipulation and Settlement Agreement in this cause and make a public version of the study available to the LaPorte County Board of Commissioners.

2) LaPorte County Economic Development Study

NIPSCO agrees to study LaPorte County to identify sites/properties that are potentially suitable for locating a large economic development project or a combined cycle gas turbine, gas peaker generating plant, battery energy storage systems, or other energy technologies that would generate local tax revenue and keep good paying jobs in LaPorte County. NIPSCO shall use commercially reasonable efforts to complete this study within six (6) months of the issuance of a final order approving the Stipulation and Settlement Agreement in this cause and make a public version of the study available to the LaPorte County Board of Commissioners.

3) LaPorte County Economic Development – Investment for Site Readiness

Through December 31, 2030, NIPSCO will work with LaPorte County, the NWI Forum, and the IEDC to identify potential economic development property(ies), and so long as LaPorte County and both NWI Forum or IEDC believe they are good property(ies) for investment (meaning, for example, site is certified as clean; it is in a designated economic development or redevelopment area, technology park, etc.; certain condition precedents have taken place such as proper zoning and site plan approval). NIPSCO agrees to make investments of up to $5 million at a property(ies) within LaPorte County to ensure electric service is available for

the property(ies) and enhance the attractiveness of such property(ies) for potential economic development customers.

4) LaPorte County Kingsbury Industrial Park

In Cause No. 44733, NIPSCO agreed to the inclusion of an Economic Development project for LaPorte County Kingsbury Industrial Park, with a stated commitment to invest as much as $3.5 million for distribution system and substation upgrades associated with such a project, once the necessary project plans have been finalized ("Kingsbury Project"). In Cause No. 45557 NIPSCO agreed to extend this commitment in its 2021-2026 Electric TDSIC Plan. NIPSCO is willing to continue to work with LaPorte County and support inclusion of the Kingsbury Project in the TDSIC Plan following the expiration of NIPSCO's 2012-2026 Electric TDSIC Plan and make these funds available through December 31, 2030.

5) Non-Opposition to Any Settlement & Admission of Prefiled Testimony

To the extent a settlement of all issues is reached in this cause and that all parties either support or do not oppose the settlement, the LaPorte County Board of Commissioners agree to not oppose such settlement. However, to the extent a settlement is reached on less than all the issues in this cause, the LaPorte County Board of Commissioners would not be restricted from taking any positions on non-settled issues. NIPSCO agrees to not oppose the admission of the prefiled testimony of all LaPorte County Board of Commissioners witnesses filed in this cause. The LaPorte County Board of Commissioners likewise agrees to not oppose the admission of the prefiled testimony of all NIPSCO witnesses filed in this cause.

6) Reservation of Rights

Nothing in this agreed addendum will be construed to limit the LaPorte County Board of Commissioners' right to intervene in other causes in which NIPSCO or NIPSCO Generation LLC is a petitioner.

ACCEPTED AND AGREED this 5th day of February, 2025.
[SIGNATURE PAGES FOLLOW]

Addendum A
Cause No. 46120

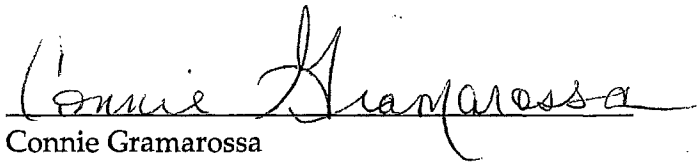
Northern Indiana Public Service Company LLC



Erin A. Whitehead
Vice President, Regulatory and Major Accounts

Addendum A

LaPorte County Board of Commissioners



Connie Gramarossa
President of the LaPorte County Board of Commissioners

Addendum B
Cause No. 46120

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

- The RV Group will be a signatory to the Settlement Agreement, which includes stipulating to the admissibility of all Settling Parties' prefiled direct, cross-answering and rebuttal testimonies and exhibits, and waiving cross-examination of all Settling Parties' and RV Group witnesses, but RV Group reserves the right to ask questions of any witness that is required to appear, and RV Group members will receive the benefits of all terms, benefits, and obligations under this section as well as the broader Stipulation and Settlement Agreement, including the agreed-to revenue requirement reductions, NIPSCO commitments, and related cost-of-service shifts.
- In Addendum B to the Stipulation and Settlement Agreement approved in Cause No. 45772, NIPSCO committed to fund energy efficiency audits of up to $50,000 per customer for each of the four RV Group members. For each of the three RV Group members in this proceeding, NIPSCO commits an additional $50,000 per customer, for a total of $100,000 per RV Group member for these three members ($50,000 from Cause No. 45772 plus $50,000 from this proceeding) which can be utilized for energy efficiency audits and/or load and usage studies. NIPSCO will also commit to assist with this study and review of the respective RV Group member's specific operational and usage characteristics, with the ultimate goal of determining if a new or adjusted rate structure or schedule is appropriate for these RV Group customers and other customers with similar characteristics who would qualify. NIPSCO and the RV Group members will work together to select a mutually satisfactory, qualified company or consultant to perform these studies. NIPSCO further commits to provide an additional $75,000 in total ($25,000 for each of the three RVG Members in this proceeding), which can be utilized toward performing load and rate studies to determine if adjustments to NIPSCO's existing rate structure or creation of a new rate for the RVG members involved in this case are appropriate to propose in the future which will require the assistance, support, and timely provision of usage and rate design data and details by NIPSCO. As part of these efforts, NIPSCO agrees to make any and all requested and relevant information timely available to the RV Group and/or their consultants, subject to any necessary non-disclosure agreements.

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

- NIPSCO agrees to include RV Group representatives in discussions with the DSM Oversight Board related to participating in existing or proposing additional demand response program opportunities available to or that could be expanded to provide additional benefits to RV Group members and lower NIPSCO peak energy needs. NIPSCO is separately committed to issuing a request for information for demand response as part of its next RFP that shall include and allow for RV Group member proposals consistent with these objectives.
- NIPSCO will continue to work separately from the DSM Oversight Board process and directly work with and assist the RV Group representatives in determining potential savings, programs, and funding opportunities through its current DSM programs and any mutually beneficial other demand-side management ("DSM") expanded processes or programs. To the extent savings are identified that are not currently part of NIPSCO's DSM current programs/measures, NIPSCO will make a good faith effort to propose and add such programs/measures to its Commission-approved DSM plan(s).
- As part of its next electric base rate case, subject to any necessary non-disclosure protections, NIPSCO agrees to prepare a 4CP cost of service analysis for purposes allocating production-related costs and make this available to the RV Group in advance of such filing, as well as to any other party subsequently participating in the case who requests it. This analysis shall conform to and be consistent with the principles of cost causation identified by NIPSCO in this and NIPSCO's last base rate case in Cause No. 45772. This does not, however, limit NIPSCO in determining which cost of service analysis it chooses to propose in its case-in-chief, nor does it impact any other parties' right to take any position with regards to cost of service or allocations in that next rate case.
- NIPSCO commits to meeting with RV Group representatives to review and discuss cost of service concerns before NIPSCO files its next electric base rate case is filed.

RV Group TDSIC Project(s)

- NIPSCO and the RV Group agree that the RV Group may propose one or more RV Group specific projects as part of its TDSIC Plan (currently under Cause No. 45557) totaling up to $5.6 Million, provided each project meets the applicable requirements of the TDSIC Statute (Ind. Code ch. 8-1-39). This agreed upon commitment and benefit shall be reserved for the benefit of the RV Group members, and any TDSIC Plan project request made by an RV Group member shall be for qualifying infrastructure upgrade needs that

improve reliability and/or spur economic development, which include, but are not limited to upgrades to substations, transformers, distribution and transmission facilities, or other necessary electrical system upgrades to provide service to an RV Group member ("RV Group TDSIC Project(s)"). This total amount of $5.6 million is inclusive of the $3.5 million RV Group Project fund provided for in Addendum B to the Stipulation and Settlement Agreement approved in Cause No. 45772, with an additional $2.1 million added to such fund.[2] Any RV Group TDSIC Project may be pursued as part of NIPSCO's existing TDSIC process in Cause No. 45557 or in subsequent TDSIC plans if the total $5.6 million has not been utilized. The Fund shall not lapse or be transferred to other NIPSCO customers, but any NIPSCO system upgrades or facilities built to support any RV Group TDSIC Project(s) may also be used to serve other customers, provided this does not diminish service reliability for the RV Group TDSIC Project(s), and the Fund shall continue until fully utilized for RV Group TDSIC Project(s).

- RV Group TDSIC Project(s) shall include any-and-all projects that qualify under the TDSIC Statute. NIPSCO will file for approval of the RV Group TDSIC Project(s) to allow the RV Group TDSIC Projects to include as many qualifying types of projects as possible, including: (i) RV Group operation or production facility updates or expansions that will result in continued or increased energy demand or continued or increased employment by the applying RV Group member from new capital investments made within the NIPSCO service territory; (ii) support of RV Group member renewable energy projects, energy efficiency and demand response, or peak load reduction projects; and (iii) any advanced or smart meter technology that will assist an RV Group member in reducing peak load. To the extent that a project proposed by an RV Group member does not qualify under the TDSIC Statute but would qualify under NIPSCO's DSM tracker, NIPSCO will seek inclusion of qualifying projects in the DSM tracker, and these projects would not count against the $5.6 million total RV Group TDSIC Project amount.
- Each of the RV Group members shall be entitled to request one or more RV Group TDSIC Project(s) subject to the review and support of NIPSCO, which support and approval shall not be unreasonably withheld or delayed. Any

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[2] This new $2.1 million fund shall be available to the RV Industry User's Group comprised of LCI Industries, Inc., Forest River, Inc., and Thor Industries. The prior 45772 $3.5 million fund shall be carried forward and continued to be made available to the RV Industry User's Group that was comprised of LCI Industries, Inc., Forest River, Inc., Thor Industries, and Patrick Industries.

requests to support RV Group TDSIC Project(s) from the Fund will be presented in a tracker filing by NIPSCO in Cause No. 45557-TDSIC-X (or successor docket), which will require and provide a sufficient evidentiary showing consistent with the TDSIC Statute for the approval of such amounts.

- All other participating Parties in the then pending TDSIC docket shall be provided notice of and reserve the right to timely take any position on such RV Group TDSIC Project(s) funding request when the request is formally presented in the TDSIC tracker filing.
- NIPSCO and the RV Group shall work together in good faith to establish precise administrative details for applications or requests for RV Group TDSIC Project(s), and such applications or requests can be made any time after approval of the Settlement Agreement, consistent with the language and requirements herein.

ACCEPTED AND AGREED this 7th day of February, 2025.

[SIGNATURE PAGES FOLLOW]

Addendum B
Cause No. 46120

Northern Indiana Public Service Company LLC

Erin A. Whitehead
Vice President
Regulatory and Major Accounts

Addendum B
Cause No. 46120

RV Industry User's Group

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 107
Vectren 2014 IRP



VECTREN
Live Smart

Vectren Corporation
2014 Integrated Resource Plan



By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

November 1, 2014

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IRP Proposed Draft Rule Requirements Cross Reference Table

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4	**Methodology and documentation requirements**	
	(a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences. (1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request as part of a contemporary issues meeting. The summary shall describe, in simple terms, the IRP public advisory process, if applicable, and core IRP concepts, including resource types and load characteristics. (2) The utility shall utilize a simplified format that visually portrays the summary of the IRP in a manner that makes it understandable to a non-technical audience. (3) The utility shall make this document readily accessible on its website.	Technical Appendix J and www.vectren.com/irp
	(b) An IRP must include the following: (1) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Included throughout the IRP

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4 Cont.	(2) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be referenced. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP, or as specified by the commission.	72, 190-191, Technical Appendix sections: A, B, D, E, F, I
	(3) A description of the utility's effort to develop and maintain a data base of electricity consumption patterns, by customer class, rate class, NAICS code, and end-use. The data base may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	72
	(4) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	92
	(5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	84-85
	(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	66-89, 186-200
	(7) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	190
	(8) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission regulated through an emission allowance system have been taken into account and influenced the IRP development.	51-55
	(9) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	186-192

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4 Cont.	(10) A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715: (A) Most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The simulation must include the capability of meeting the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it. (D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.	175-183
	(11) An explanation of the contemporary methods utilized by the utility in developing the IRP, including a description of the following:	
	(A) Model structure and reasoning for use of particular model or models in the utility's IRP.	66-67, 186-187
	(B) The utility's effort to develop and improve the methodology and inputs for its:	32, 186
	(i) forecast;	32, 93
	(ii) cost estimates;	32, 99, 190-191
	(iii) treatment of risk and uncertainty; and	32, 190
	(iv) evaluation of a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:	32
	(AA) transmission; and	176-177
	(BB) generation.	32

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-4 Cont.	(12) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	139, Technical Appendix B
	(13) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically and may be a separate file from the IRP. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Technical Appendix G
	(14) Publicly owned utilities shall provide a summary of the utility's: (A) most recent public advisory process; (B) key issues discussed; (C) how they were addressed by the utility.	20-21, Technical Appendix A
170 IAC 4-7-5	**Energy and demand forecasts**	
	(a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:	
	(1) Historical load shapes, including, but not limited to, the following:	90-92, Technical Appendix C
	(A) Annual load shapes.	
	(B) Seasonal load shapes.	
	(C) Monthly load shapes.	
	(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	
	(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	
	(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	28, 69
	(4) Actual and weather normalized energy and demand levels.	90

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-5 Cont.	(5) A discussion of all methods and processes used to normalize for weather.	72-73
	(6) A minimum twenty (20) year period for energy and demand forecasts.	67-71
	(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following: (A) Total system. (B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	94-96
	(8) Justification for the selected forecasting methodology.	66-67, 76-77
	(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(b)(2) of this rule.	89
	(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Changes in technology. (5) Behavioral factors affecting customer consumption. (6) State and federal energy policies. (7) State and federal environmental policies.	70-71
170IAC 4-7-6	**Resource Assessment**	
	(a) The utility shall consider continued use of an existing resource as a resource alternative in meeting future electric service requirements. The utility shall provide a description of the utility's existing electric power resources that must include, at a minimum, the following information:	189
	(1) The net dependable generating capacity of the system and each generating unit.	189
	(2) The expected changes to existing generating capacity, including, but not limited to, the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	28
	(3) A fuel price forecast by generating unit.	190-191

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170IAC 4-7-6 Cont.	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	51-58
	(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	175-183
	(6) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	69, 121-131, 152-171
	The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall also be provided for each year of the planning period.	
	(b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's IRP shall, at a minimum, include the following:	122-129
	(1) A description of the demand-side program considered.	153-171
	(2) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	140
	(3) The customer class or end-use, or both, affected by the program.	153-171
	(4) A participant bill reduction projection and participation incentive to be provided in the program.	153-171

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170IAC 4-7-6 Cont.	(5) A projection of the program cost to be borne by the participant.	153-171
	(6) Estimated energy (kWh) and demand (kW) savings per participant for each program.	153-171
	(7) The estimated program penetration rate and the basis of the estimate.	153-171
	(8) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	153-171
	(c) A utility shall consider a range of supply-side resources including cogeneration and nonutility generation as an alternative in meeting future electric service requirements. This range shall include commercially available resources or resources the director may request as part of a contemporary issues technical conference. The utility's IRP shall include, at a minimum, the following:	109, 112
	(1) Identify and describe the resource considered, including the following:	109
	(A) Size (MW).	109
	(B) Utilized technology and fuel type.	109
	(C) Additional transmission facilities necessitated by the resource.	180-182
	(2) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	N/A
	(d) A utility shall consider new or upgraded transmission facilities as a resource in meeting future electric service requirements, including new projects, efficiency improvements, and smart grid resources. The IRP shall, at a minimum, include the following: (1) A description of the timing and types of expansion and alternative options considered. (2) The approximate cost of expected expansion and alteration of the transmission network. (3) A description of how the IRP accounts for the value of new or upgraded transmission facilities for the purposes of increasing needed power transfer capability and increasing the utilization of cost effective resources that are geographically constrained.	175-183

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170IAC 4-7-6 Cont.	(4) A description of how: (A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and (B) RTO planning and implementation processes are used in and affect the IRP.	38-48
170 IAC 4-7-7	**Selection of future resources**	
	(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through 6(c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in, but not limited to, a resource summary table. The following information: (1) Significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge.	109
	(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	188
	(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e): (1) Participant. (2) Ratepayer impact measure (RIM). (3) Utility cost (UC). (4) Total resource cost (TRC). (5) Other reasonable tests accepted by the commission.	137-151
	(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	138, 153-154
	(d) A utility is required to:	
	(1) specify the components of the benefit and the cost for each of the major tests; and	137-138
	(2) identify the equation used to express the result.	137

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-7 Cont.	(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	137-151
	(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8	**Resource integration**	
	(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.	186-187
	(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:	193-201
	(1) Describe the utility's preferred resource portfolio.	193-194, 201
	(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.	202-211
	(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.	171-172
	(4) Demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply.	84-89, 109, 112, 122-132, 171-172
	(5) Discuss the utility's evaluation of targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	179, 137-140

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-8 Cont.	(6) Discuss the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio. The discussion of the preferred resource portfolio shall include, where appropriate, the following: (A) Operating and capital costs. (B) The average cost per kilowatt-hour, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	N/A
	(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost effective risk and uncertainty reduction, including the following. (A) Identification and explanation of assumptions. (B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to: See below. (i) regulatory compliance; (ii) public policy; (iii) fuel prices; (iv) construction costs; (v) resource performance; (vi) load requirements; (vii) wholesale electricity and transmission prices; (viii) RTO requirements; and (ix) technological progress. (C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.	201-212
	(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.	Technical Appendix H

Rule Reference	Rule Description	Report Reference (As Page # or Attachment)
170 IAC 4-7-8 Cont.	(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.	201-212
	(8) Demonstrate, to the extent practicable and reasonable, that the preferred resource portfolio incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances quickly and appropriately. Unexpected changes include, but are not limited to, the following: See below. (A) The demand for electric service. (B) The cost of a new supply-side or demand-side technology. (C) Regulatory compliance requirements and costs. (D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	201-212
170 IAC 4-7-9	**Short term action plan**	
	Sec. 9. A short term action plan shall be prepared as part of the utility's IRP, and shall cover each of the three (3) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. The short term action plan must include, but is not limited to, the following: (1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) The implementation schedule for the preferred resource portfolio. (3) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (4) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	215-216

List of Acronyms/Abbreviations

AC	Air Conditioning
ACS	American Community Survey
AMI	Advanced Metering Infrastructure
APWR	Advanced Pressurized Water Reactor
ARRA	American Recovery and Reinvestment Act
ASPEN-OneLiner	Advanced Systems for Power Engineering, Incorporated
AUPC	Average Use Per Customer
B	Water Heating Service – Closed to new customers
BAGS	Broadway Avenue Gas Turbines
BPJ	Best Professional Judgment
BPM	MISO's Business Practice Manual
BTU	British Thermal Unit
CAA	Clean Air Act
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Days
CEII	Critical Electric Infrastructure Information
CFL	Compact Fluorescent Lighting
CHP	Combined Heat and Power
CIL	Capacity Import Limit
CO_2	Carbon Dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DA	Distribution Automation
DGS	Demand General Service
DLC	Direct Load Control
DOE	United States Department of Energy
DR	Demand Response
DRR-1	Demand Response Resource Type 1
DSM	Demand-side Management
DSMA	Demand Side Management Adjustment
EAP	Energy Assistance Program
ECM	Electronically Commutated Motor
EDR	Emergency Demand Response
EEFC	Energy Efficiency Funding Component
EGU	Electric Generating Units
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
ELGS	Effluent Limit Guidelines and Standards
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EVA	Energy Ventures Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GS	General Service
GWH	Gigawatt Hour
HAP	Hazardous Air Pollutants
HCi	Hydrochloric Acid

List of Acronyms/Abbreviations (continued)

HDD	Heating Degree Days
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Interconnection Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producers
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kVA	Kilovolt-Ampere
kWh	Kilowatt Hour
LBA	Load Balancing Area
LCR	Local Clearing Requirement
LMR	Load Management Receivers
LP	Large Power
LRZ	Local Resource Zone
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MACT	Maximum Achievable Control Technology Standards
MAPE	Mean Absolute Percentage Error
MARS	Multi-Area Reliability Simulation
MATS	mercury and Air Toxics Standards
MECT	Module E Capacity Tracking
MGD	Millions of Gallons per Day
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBTU	One million British Thermal Unit
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
NAICS	North American Industry Classification System
NDC	Net Dependable Capacity
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data, and Analysis
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrous Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NSPS	New Source Performance Standards
O&M	Operation and Maintenance
ORSANCO	Ohio River Valley Sanitation Commission
OSS	Off Season Service
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PRM	Planning Reserve Margin
PTI-PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PV	Photovoltaic
PVRR	Present Value of Revenue Requirements
RBS	Residential Behavioral Savings

List of Acronyms/Abbreviations (continued)

RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RECB	Regional Expansion Criteria and Benefits
RFC	Reliability First Corporation
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
RS	Residential Service
SAE	Statistically Adjusted End-use
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SGS	Small General Service
SGT	Steam Turbine Generator
SIP	System Integration Plan
SMR	Small Modular Reactors
SO_2	Sulfur Dioxide
TPA	Third Party Administrator
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity Rating
VUHI	Vectren Utility Holdings Inc.
ZRC	Zone Resource Credit

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CHAPTER 1
EXECUTIVE SUMMARY

COMPANY BACKGROUND

Vectren Corporation is an energy holding company headquartered in Evansville, Indiana. Vectren's wholly owned subsidiary, Vectren Utility Holdings, Inc. (VUHI), is the parent company for three operating utilities: Indiana Gas Company, Inc. (Vectren North), Southern Indiana Gas and Electric Company (Vectren), and Vectren Energy Delivery of Ohio (VEDO).

Vectren North provides energy delivery services to more than 570,000 natural gas customers located in central and southern Indiana. Vectren provides energy delivery services to over 142,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. VEDO provides energy delivery services to approximately 312,000 natural gas customers near Dayton in west central Ohio.

Vectren's company-owned generation fleet represents 1,158 megawatts (MW)[1] of unforced capacity (UCAP) as shown in Table 1-1.

Table 1-1 Generating Units

Unit	UCAP (MW)	Primary fuel	Commercial Date
Northeast 1	9 MW	Gas	1963
Northeast 2	9 MW	Gas	1964
FB Culley 2	83 MW	Coal	1966
Warrick 4	135 MW	Coal	1970
FB Culley 3	257 MW	Coal	1973
AB Brown 1	228 MW	Coal	1979
BAGS 2	59 MW	Gas	1981
AB Brown 2	233 MW	Coal	1986
AB Brown 3	73 MW	Gas	1991
AB Brown 4	69 MW	Gas	2002
Blackfoot	3 MW	Landfill Gas	2009

[1] Blackfoot landfill gas project is considered behind-the-meter and is therefore currently accounted for as a reduction to load and is omitted from the capacity total

In addition to company owned generating resources, Vectren has access to an additional 30 MW of capacity as a result of its 1.5% ownership interest in Ohio Valley Electric Corporation (OVEC). Vectren is also contracted to receive 80 MW of nominal capacity wind energy through two separate long-term purchase power agreements. The total firm capacity credit for the MISO 2014-2015 planning year for these wind resources is 7.3 MW. Vectren is interconnected with other utilities at both 345 kV and 138 kV and is able to exchange capacity and energy through the market mechanisms of the Midcontinent Independent System Operator (MISO).

THE IRP PROCESS

The Integrated Resource Plan (IRP) process was developed to assure a systematic and comprehensive planning process that produces a reliable, efficient approach to securing future resources to meet the energy needs of the utility and its customers. The IRP process encompasses an assessment of a range of feasible supply-side and demand-side alternatives to establish a diverse portfolio of options to effectively meet future generation needs.

In Indiana, the IRP is also guided by rules of the Indiana Utility Regulatory Commission (IURC). Those rules, found in the Indiana Administrative Code at 170 I.A.C. 4-7-4 through 4-7-9, provide specific guidelines for plan contents and filing with the Commission. On October 14, 2010, the IURC issued an order to commence rulemaking to revise/update the current Indiana IRP rule. The following summer, Vectren participated in a stakeholder process to provide input on updating the rule. The proposed draft rule was sent to stakeholders on October 4, 2012. Although not finalized, Vectren voluntarily followed the proposed draft rule, which is found in the IRP Proposed Draft Rule Requirements Cross Reference Table of this IRP.

Vectren modified its processes to meet the proposed draft rule. Most notably, Vectren incorporated a stakeholder process to gather input from stakeholders and answer stakeholder questions in an open, transparent process. The proposed rule requires at

least 2 meetings with stakeholders. On March 20, 2014, Vectren met with stakeholders to discuss the base inputs of the plan, educate stakeholders on IRP related topics, and review the Vectren process. Based on feedback from stakeholders, Vectren added an additional meeting on August 5, 2014 to further discuss major assumptions and data inputs prior to modeling. Finally, on September 24, 2014 Vectren presented a preview of the plan. A summary of the stakeholder meetings can be found in Chapter 2 Planning Process, and the meeting presentations and Q&A summaries are found in the Technical Appendix, section A.

Details of the process used by Vectren to develop the recommended plan in this IRP are found in chapters 2 through 11 of this report. Chapter 11 Action Plan sets forth the action plan for Vectren over the next three years to achieve the long-term resource objectives described in this IRP.

Included in the process is an updated demand and energy forecast (detailed in Chapter 5 Sales and Demand Forecast). Table 1–2, shows a summary of the demand and energy forecast.

VECTREN'S QUANTITATIVE AND QUALITATIVE IRP PROCESS

Historically, Vectren has used modeling to perform the evaluations, screenings, and assessments of various potential scenarios to arrive at a single plan that represented its "Resource Plan Additions." Vectren continues to use the Strategist modeling software from Ventyx, as it has in its last several IRP studies. This software has traditionally been used by some of the other Indiana utilities, as well. The submitted plan was the result of a process that was primarily a quantitative evaluation performed using an industry standard planning model.

The modeling performed by Vectren provides important information to evaluate future resource needs. However, Vectren will also continue to monitor developments that

could impact future resource needs. Three developments that Vectren is focusing on for impacts on the near term are:

1. The Clean Power Plan from the Environmental Protection Agency (EPA) and Indiana's approach to implementing this rule.
2. MISO capacity market constraints resulting from the early retirements of coal units as a response to the EPAs MATS rule.
3. The impacts on Vectren's load due to the addition of or loss of large customer load.

While Vectren's models attempt to evaluate the impact those issues may have on its future load, significant uncertainty remains. Vectren must maintain flexibility to adjust its plans based on the outcome of these and other unknown factors. In the case of Vectren, one of the smallest investor-owned electric utilities in the nation, the ramifications of major capacity decisions are particularly important.

Equally important, Vectren believes one of the major objectives of the Commission's reporting and filing requirements regarding the IRP process is to communicate with the IURC regarding the decision processes, evaluations, and judgments that Vectren uses to assist in making the resource planning decisions that are in the long-term best interest of Vectren's customers and the communities it serves. Vectren understands that the action plan which results from the IRP process is to be used as a guide by the Company and the IURC in addressing long-term resource needs, as both attempt to carry out their respective responsibilities in the most effective manner possible.

CHANGES SINCE LAST IRP

While a number of changes have occurred since Vectren's last IRP, four specific changes have had a significant impact on this IRP. First, the IURC's proposed draft IRP rules were released after Vectren's last IRP. Vectren is voluntarily following the new proposed draft IRP rule, which includes a stakeholder process, non-technical summary, more robust risk analysis, and attending an annual contemporary issues meeting in Indianapolis. The IRP Proposed Draft Rule Requirements Cross Reference Table on

page three shows the new proposed draft rule and where Vectren addresses each part in this IRP.

Second, Vectren engaged a third party consultant with significant experience conducting IRPs for other parties, Burns & McDonnell, one of the leading engineering design experts in the United States, to aid its preparation of this IRP. For the 2014 IRP, Vectren worked closely with Burns and McDonnell to perform Strategist modeling (including additional DSM modeling). Burns and McDonnell has a great deal of experience in working with companies across the country on resource modeling. They also performed the Technology Assessment, detailing costs for potential resource options. The Technology Assessment can be found in the Technical Appendix, section B.

Third, the EPA has finalized various federal mandates with respect to further environmental regulation of Vectren's generating units and proposed a sweeping greenhouse gas regulation for existing coal-fired generating sources since Vectren's last IRP. As will be discussed in more detail in Chapter 4 Environmental, the EPA finalized its Mercury and Air Toxics Standard (MATS) in 2012, which set first ever plant-wide emission limits for mercury and other hazardous air pollutants and has a compliance deadline of April 2015. MATS has resulted in many announcements of coal plant retirements across the US. As a result, MISO, Vectren's Regional Transmission Operator (RTO), is predicting potential capacity shortfalls in the next few years. In the next two years Vectren intends to spend $70- $90 million on its environmental compliance program to meet not only the MATS rule, but also recent water discharge limits for mercury contained in water discharge permit renewals and mitigate incremental sulfur trioxide (SO_3) emissions resulting from the installation of Vectren's selective catalytic reduction technology under an agreement with the EPA. However, Vectren is projecting to defer recovery of these federally mandated costs until approximately 2020. The assumptions in the IRP are consistent with Vectren's environmental compliance filing.

In addition to the federal mandates referenced above, the EPA released its final rule regulating cooling water structures under Section 316(b) of the Clean Water Act (CWA) on August 15, 2014. Section 316(b) requires that intake structures that withdraw > 2 Million Gallons per Day (MGD) of water, including most electric generating units, use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a water body. This rule applies only to the FB Culley plant, as the AB Brown plant already utilizes cooling water towers.

Finally, on June 2, 2014, the EPA issued the Clean Air Act Section 111(d) Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for existing sources, known as the Clean Power Plan (CPP). The CPP sets state-specific carbon reduction goals based on a state's existing generation mix based upon a building block approach and provides guidelines for the development, submission and implementation of state plans to achieve the state goals. As yet, there is little clarity on how the state of Indiana will choose to implement this rule. However, this IRP considers several of the potential building blocks in its assumptions: Demand Side Management (DSM), a potential renewables portfolio standard, and a price for carbon price beginning in 2020.

Fourth, the Indiana General Assembly passed legislation in March of 2014 that modified DSM requirements in Indiana. Senate Enrolled Act No. 340 ("SEA 340") removed requirements for mandatory statewide "Core" DSM programs and energy savings goals effective December 31, 2014. SEA 340 also allows large Commercial and Industrial (C&I) customers who meet certain criteria to opt-out of participating in utility sponsored DSM programs.

Vectren continues to support DSM related energy efficiency efforts as a fundamental part of the services that are provided to customers in order to help them manage their energy bills. Vectren believes that a cost effective level of DSM energy efficiency may be supported by policy considerations beyond the IRP's focus on planning for future

resources. Consistent with this belief, Vectren's base sales forecast includes a base level of DSM at a targeted level of 1% eligible annual savings for 2015 – 2019 and 0.5% annually thereafter for customer load that has not opted-out of DSM programs.

Vectren also modeled whether incremental DSM energy efficiency programs would be selected as a resource when competing with supply side options, to meet future electric requirements. Vectren's approach attempts to balance its commitment to a level of cost-effective DSM to help customers manage their energy bills, while evaluating additional DSM resources consistent with least cost planning.

Note that since the last IRP was performed, Broadway Unit 1 (BAGS 1) has quit performing up to specifications. The unit has been on a long-term outage. Therefore, Vectren currently does not get credit for the unforced capacity (UCAP) amount, and it was not included in the analysis as shown in Table 1-1. BAGS 1 is a natural gas peaking unit, and in the past was typically good for approximately 40 MW on a UCAP basis.

PLAN RESULTS / RECOMMENDATIONS

The IRP indicates that Vectren does not need any incremental generation resources or purchase power agreements during the planning horizon. Although the IRP does not project incremental resource needs, Vectren proposes to continue offering DSM programs to help customers use less energy, thus lowering their total bill. The IRP forecasts that there may be some marginal economic benefit to retiring FB Culley 2 in 2020 under certain scenarios. This retirement evaluation is influenced by Vectren's load forecast, carbon costs, and fuel costs. Vectren will continue to evaluate the impact of these components on Culley Unit 2 in successive IRPs to evaluate the optimal time to retire Culley Unit 2.

As mentioned above and discussed in further detail in this IRP, the decision to retire FB Culley 2 will not be made until major near term uncertainties become more clear, most

notably how the state of Indiana will implement the EPA's Clean Power Plan (if the plan survives legal challenges). Additionally, Vectren is actively working to attract new industrial customers through economic development activities in southwestern Indiana. If a large customer chooses to locate within the Vectren electric service area, Culley 2 will be required to operate at least in the short term to provide the resources necessary to serve such a customer. Leaving Culley Unit 2 in operation at this time provides Vectren maximum flexibility to adapt to such future developments. Economic modeling does not necessarily account for all such developments that are very possible, and therefore, judgment must also be part of the analysis. Table 1-2 shows the peak and energy forecast. Table 1-3 shows that no capacity additions are currently deemed necessary.

Vectren's base case scenario assumptions are detailed in Chapter 10 Generation Planning. In summary, Vectren assumed a minimum planning margin of 7.3%[1] for each year of the study. Energy savings goals of 1% of eligible customer load were incorporated into the load forecast through 2019. Additionally, incremental energy savings of .5% per year were assumed beginning in 2020 and were carried throughout the rest of the planning period. All assumptions are discussed in depth throughout this IRP.

Sensitivity risk analyses were performed around coal, gas, energy, and carbon pricing, capital costs, and high environmental regulation cost. These results are shown in Chapter 10 Generation Planning.

CONCLUSION

Vectren recognizes that the electric utility industry is experiencing a fast-changing time in terms of potential regulations, environmental mandates, and technology advances. Given the significant impact of any resource decision on both customers and other stakeholders, Vectren will continue to actively monitor developments in the regulatory,

[1] MISO unforced capacity (UCAP) requirement, further discussed in Chapter 3 MISO

environmental, and technology arenas for both their impact on future generation needs and existing facilities. Open communication with the IURC and other parties including the OUCC will be key to Vectren's ability to make the best decisions for all stakeholders.

Table 1-2 Peak and Energy Forecast

Year	Peak (MW)[1]	Annual Energy (GWh)
2014 Proj.	1,145	5,782
2015	1,155	5,914
2016	1,156	5,936
2017	1,113	5,514
2018	1,109	5,503
2019	1,106	5,494
2020	1,106	5,497
2021	1,106	5,492
2022	1,107	5,494
2023	1,107	5,494
2024	1,107	5,496
2025	1,106	5,487
2026	1,106	5,487
2027	1,107	5,492
2028	1,109	5,507
2029	1,110	5,509
2030	1,111	5,517
2031	1,111	5,523
2032	1,113	5,540
2033	1,114	5,548
2034	1,115	5,560
Compound Annual Growth Rate, 2014-2034	-0.1%	-0.2%

[1] Includes wholesale contract sales for 2014

Table 1-3 Base Case Resource Plan

Year	Firm Peak Demand[1] (MW)	UCAP Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	UCAP Committed Purchases (MW)	Capacity Additions (MW)	Total Resources (MW)	Reserve Margin (%)[2]
2015	1,155	1,155	17	50	38		1,260	9.1%
2016	1,156	1,155	17	50	38		1,260	9.0%
2017	1,113	1,155	18	27	38		1,238	11.2%
2018	1,109	1,155	18	27	38		1,238	11.6%
2019	1,106	1,155	17	28	38		1,238	11.9%
2020	1,106	1,155	17	28	38		1,238	11.9%
2021	1,106	1,155	17	28	38		1,238	11.9%
2022	1,107	1,155	17	28	38		1,238	11.8%
2023	1,107	1,155	17	28	38		1,238	11.8%
2024	1,107	1,155	17	28	38		1,238	11.8%
2025	1,106	1,155	17	28	38		1,238	11.9%
2026	1,106	1,155	17	28	38		1,238	11.9%
2027	1,107	1,155	17	28	38		1,238	11.8%
2028	1,109	1,155	17	28	38		1,238	11.6%
2029	1,110	1,155	17	28	38		1,238	11.5%
2030	1,111	1,155	17	28	38		1,238	11.4%
2031	1,111	1,155	17	28	38		1,238	11.4%
2032	1,113	1,155	17	28	38		1,238	11.2%
2033	1,114	1,155	17	28	38		1,238	11.1%
2034	1,115	1,155	17	28	38		1,238	11.0%

[1] Vectren is not forecasting firm wholesale contracts throughout this forecast.
[2] MISO requires a 7.3% Planning Reserve

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CHAPTER 2

PLANNING PROCESS

INTRODUCTION

Vectren's IRP objectives are based on the need for a resource strategy that provides value to its customers, communities, and shareholders. In addition, this strategy must accommodate the ongoing changes and uncertainties in the competitive and regulated markets. Specifically, Vectren's IRP objectives are as follows:

- Provide all customers with a reliable supply of energy at the least cost reasonably possible
- Develop a plan with the flexibility to rapidly adapt to changes in the market while minimizing risks
- Provide high-quality, customer-oriented services which enhance customer value
- Minimize impacts of Vectren's past and current operations on local environments

PLANNING PROCESS

The planning process is driven by the characteristics of Vectren's markets and the needs of its customers. These elements serve to define the utility's objectives and help establish a long-term forecast of energy and demand.

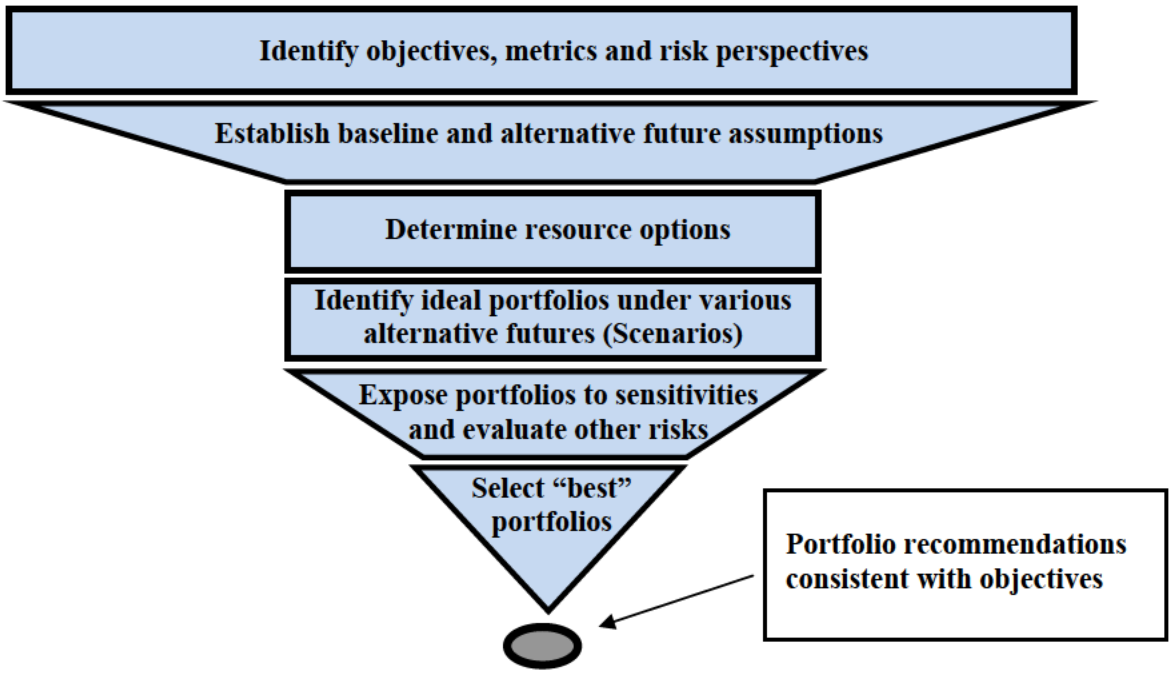
Using the forecast as a baseline, the IRP process entails evaluation of both supply-side and demand-side options designed to address the forecast. These options serve as input into a formal integration process that determines the benefits and costs of various combinations of supply-side and demand-side resources. Because the IRP modeling process requires significant amounts of data and assumptions from a variety of sources, a process is needed to develop appropriate inputs to the models.

The process criteria for inputs include:

- Maintain consistency in developing key assumptions across all IRP components
- Incorporate realistic estimates based on up-to-date documentation with appropriate vendors and available market information, as well as internal departments

- Consideration of impacts and experiences gained in prior IRP processes and demand-side program efforts

Vectren follows an integrated resource plan process that is very similar to other utilities throughout the country. In order to stay current with IRP methodologies and techniques, Vectren works with consultants, attends integrated resource planning conferences, and attends the annual contemporary issues meeting (hosted by the IURC). The diagram below illustrates the general process.



Vectren's objective is to serve customers as reliably and economically as possible, while weighing future risks and uncertainties. Vectren begins the process by forecasting customers' electric demand for 20 years. The electric demand forecast considers historical electric demand, economics, weather, appliance efficiency trends (driven by Federal codes and standards), population growth, adoption of customer owned generation (such as solar panels), and Vectren DSM energy efficiency programs (such as appliance rebates). A base, low, and two high peak load forecasts were developed.

The next step in the process is to determine possible alternative futures (scenarios) and determine how to reliably and economically meet customers' future electric demand. Vectren has adequate resource options (power plants, on-going energy efficiency and demand response options) to meet customers' need. The base scenario assumes customer need will be met with existing resources. The second scenario examines the potential impact of retiring FB Culley 2, Vectren's oldest, smallest (83 MW), and most inefficient coal generating unit. Additionally, it is not controlled for NO_x. The final scenario included a possible future where the government enacts a Renewable Portfolio Standard (RPS), requiring 20% of electricity to be produced with renewable resources, such as wind, solar, customer-owned renewable distributed generation, and utility sponsored DSM energy efficiency programs.

Each electric demand forecast is exposed to the base and two alternate futures to determine the most economical way to meet customer needs, resulting in 12 possible plans. The diagram below illustrates each alternative.

		A Base	B FB Culley 2 Unit Retirement	C RPS
1	Base Demand Forecast	Plan A1	Plan B1	Plan C1
2	Low Demand Forecast	Plan A2	Plan B2	Plan C2
3	High (modeled) Demand Forecast	Plan A3	Plan B3	Plan C3
4	High (large load) Forecast[1]	Plan A4	Plan B4	Plan C4

[1] The base demand forecast with a 100 MW firm load addition in 2018

Each plan represents the lowest-cost option to meet customer demand. Several resource options were considered in the analysis to meet customer demand, including various (types and sizes) natural gas powered generation options, additional energy efficiency programs beyond what is already included in the electric demand forecasts, renewables (wind and solar generation), and short-term market capacity purchases.

All model inputs and assumptions are loaded into a modeling tool called Strategist, which is used by many utilities throughout the country. The modeling tool optimizes for the lowest-cost plan to meet customer demand, plus a 7.3% UCAP planning reserve margin.

Each plan was then subjected to additional risk sensitivities to determine which plan is the lowest cost over a wide range of possible future risks. As previously mentioned, resource modeling requires a large number on inputs and assumptions: forecasts for natural gas prices, coal prices, market energy prices, CO_2 prices, costs of resource options, and potential costs for regulations. If the costs of any of these risk factors vary significantly from the base forecasts, the results of the analysis could potentially be different. Each plan (A1-C4) was subjected to varying costs (most often +/- 20%) for the risk factors mentioned above to determine the impact to each plan from the possible future sensitivities.

The remainder of this IRP is organized as follows:

MISO
Chapter 3 - Discusses Vectren's participation in MISO and the implications for resource planning

Environmental
Chapter 4 - Discusses current and pending environmental issues and regulations and the potential considerations for resource decisions

Forecast
Chapter 5 - Contains the electric sales and demand forecast

Supply-Side
Chapter 6 - Describes the electric supply analysis including a review and screening of the various electric supply options
Chapter 7 - Describes the viability and application of renewable and clean energy technologies and renewable energy credits (RECs)
Chapter 9 - Contains a discussion of Vectren's transmission and distribution expansion plan forecast

Demand-Side
Chapter 8 - Presents a discussion of DSM resources including screening results and program concept development

Integration
Chapter 10 - Details the formal integration process which includes conducting sensitivity analyses and obtaining the final resource plan

Short term Action Plan
Chapter 11 - Contains action plans designed to implement the resource plan over the next three years

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CHAPTER 3

MISO

INTRODUCTION

Vectren was an original signer of the Transmission Owners Agreement, which organized the Midwest Independent Transmission System Operator, now known as the Midcontinent Independent System Operator (MISO) and under which authority the MISO administers its Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). As a vertically integrated utility with the responsibility and obligation for serving load within the MISO footprint, Vectren has integrated many functions with the operating procedures of MISO. This integration involves the coordinated operation of its transmission system and generating units, and the functions range from owning and operating generation and transmission, to complying with certain reliability standards. These standards include planning and operation of resources to meet the needs of loads in the future and are set by the North American Electric Reliability Corporation (NERC) and the regional reliability entity Reliability First Corporation, both of which are overseen by the Federal Energy Regulatory Commission (FERC).

MISO OVERVIEW

MISO, headquartered in Carmel, Indiana, with additional offices in Egan, Minnesota, was approved as the nation's first regional transmission organization in 2001. Today, MISO manages one of the world's largest energy and operating reserves markets; the market generation capacity was 175,436 MW as of May 1, 2014. This market operates in 15 states and one Canadian province.

Key Dates

- February 1, 2002 - Transmission service began under MISO Open-Access Transmission Tariff with Vectren as a full Transmission Owning Member
- April 1, 2005 - Midwest markets launch
- April 16, 2008 - NERC certified MISO as Balancing Authority
- January 6, 2009 - Ancillary Services Markets began and MISO became the region's Balancing Authority
- December 19, 2013 – Added South Region

Vectren in Relation to MISO Footprint

With a native peak load of about 1,150 MW, Vectren is approximately 1.4% of the MISO market footprint and is one of 36 local balancing authorities. In addition, the Vectren transmission system supports multiple municipals and a large industrial smelter. The total control area or Local Balancing Area (LBA) is approximately 1,900 MW.

Figure 3-1 below is a drawing of the entire MISO market footprint, and Figure 3-2 shows the MISO Reliability Coordination Area.

Figure 3-1 MISO Market Area

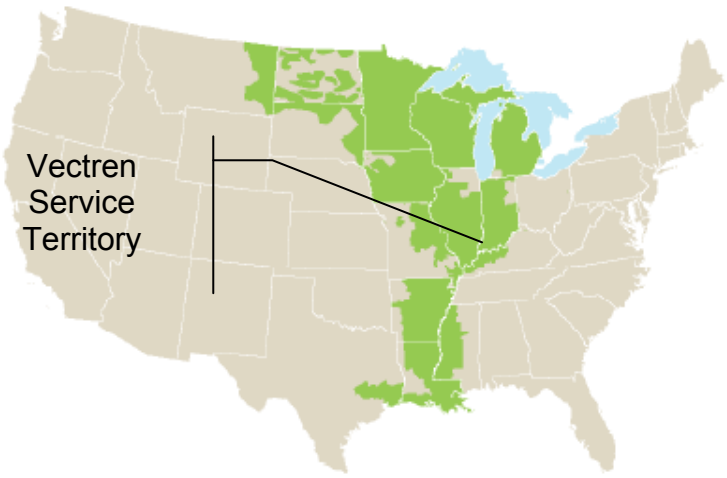
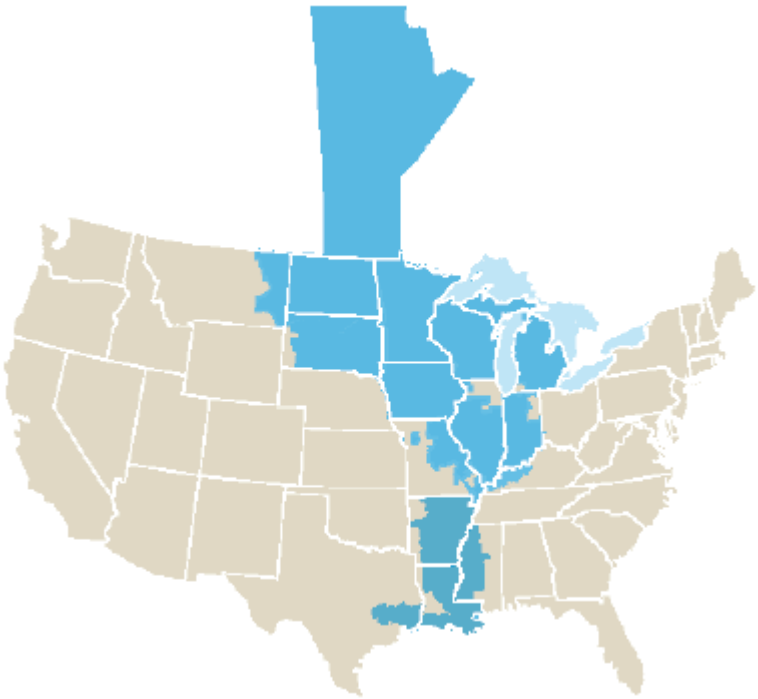


Figure 3-2 MISO Reliability Coordination Area



MISO's GOALS

The goal of MISO's regional transmission planning process is the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. This process identifies solutions for reliability issues that arise from the expected dispatch of network resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects and increased operating expenses from redispatching network resources or other operational actions.

The MISO Board of Directors has adopted six planning principles to guide the MISO regional plan:

1. Make the benefits of an economically efficient energy market available to customers by identifying transmission projects which provide access to electricity at the lowest total electric system costs.
2. Provide a transmission infrastructure that upholds all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.
3. Support state and federal energy policy requirements by planning for access to a changing resource mix.

4. Provide an appropriate cost allocation mechanism that ensures the costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
5. Analyze system scenarios and make the results available to state and federal energy policymakers and other stakeholders to provide context and to inform choices they face.
6. Coordinate transmission planning with neighboring planning regions to seek more efficient and cost-effective solutions.[1]

MISO is designated as Vectren's Planning Authority, under the NERC reliability standards, and in FERC Order 1000, MISO has additional regional planning responsibilities.

MISO PLANNING PROCESS

MISO Transmission Planning Process

MISO's transmission planning process begins with the models for the current planning cycle and includes opportunities for stakeholder input on the integration of transmission service requests, generator interconnection requests, and other studies to contribute to the development of an annual MISO Transmission Expansion Plan (MTEP) report.

The 2013 MTEP recommended $1.48 billion in 317 new projects across the MISO footprint through the year 2023. MISO MTEP process has recommended $17.9 billion total investment since its 2003 inception through the first 10 years.

[1] These Guiding Principles were initially adopted by the Board of Directors, pursuant to the recommendation of the System Planning Committee, on August 18, 2005, and reaffirmed by the System Planning Committee in February 2007, August 2009, May 2011, and March 2013.

MISO's role in meeting Vectren's requirements as a member of ReliabilityFirst for a Planning Reserve Margin

As a result of the Energy Policy Act of 2005, regional entities were delegated authority by FERC to establish standards to provide for reliable operation of the bulk-power system. Vectren is a member of regional entity ReliabilityFirst, and so must comply with regional entity Reliability First standards, including the Planning Resource Adequacy Analysis and the Assessment and Documentation Standard BAL-502-RFC-02. This assessment and documentation standard requires planning coordinators to perform annual resource adequacy analyses. This includes calculating a planning reserve margin (PRM) that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year equal to a one day in 10 year criterion. This PRM requirement also includes documenting the projected load, resource capability, and PRM for the years under study, and other particular criteria.

The first planning year the Reliability First Planning Reserve Standard was in effect (June 2008-May 2009), Vectren complied with the ReliabilityFirst Planning Resource Adequacy standard by participating in the Midwest Planning Reserve Sharing Group. The calculated required PRM for Vectren was 14.3% on an installed capacity basis. For planning year June 2009-May 2010 and beyond, Vectren and all other MISO utilities have delegated their tasks assigned to the Load Serving Entities (LSEs) under BAL-502-RFC-02 to MISO. The specific section of the MISO Tariff that addresses planning reserves is Module E-1 Resource Adequacy. Vectren is complying with the ReliabilityFirst Planning Resource Adequacy standard by meeting the MISO Module E individual LSE required PRM. This PRM (UCAP) is 7.3% for planning year June 2014 - May 2015.

MISO's Module E-1

As previously mentioned, Module E-1- Resource Adequacy is the portion of the MISO Tariff which requires MISO to determine the Planning Reserve Margin Requirement, on

an unforced capacity (UCAP) basis, that would result in 1 day in 10 Loss of Load Event reliability standard. Module E-1 and its associated business practice manual lays out the mandatory requirements to ensure access to deliverable, reliable and adequate planning resources to meet peak demand requirements on the transmission system. To perform these calculations, MISO requires entities to utilize their Module E Capacity Tracking Tool (MECT) to submit a forecast of demand and list their qualified resources. This same tool is then leveraged to accept offers into MISO's annual Planning Resource Auction (PRA).

Loss of Load Expectation and Determination of Planning Reserve Margins

MISO used a Loss of Load Expectation[1] (LOLE) of 1 day in 10 years as the probabilistic method to determine expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). This LOLE, along with other LSE-specific data, is used to perform a technical analysis on an annual basis to establish the PRM UCAP for each LSE. The PRM analysis considers other factors such as generator forced outage rates of capacity resources, generator planned outages, expected performance of load modifying resources, forecasting uncertainty, and system operating reserve requirements.

For this year, an unforced capacity planning reserve margin of 7.3% applied to the MISO system Coincident Peak Demand has been established for the planning year of June 2014 through May 2015. This value was determined by MISO through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis.

Effect of Load Diversity

Within Module E-1, individual LSEs maintain reserves based on their Coincident Peak Demand, which is the LSE's demand at the time of the MISO peak. MISO no longer calculates a Load Diversity Factor for LSE's, as this would be different for each LSE. However, each LSE peaks at a different time, and for reference, an LSE can determine

[1] Included in the Technical Appendix, section I

what the PRM UCAP would be when accounting for load diversity by multiplying the PRM UCAP times the ratio of LSE Coincident Peak Demand divided by LSE peak Demand.

Forecast LSE Requirements

LSEs must demonstrate that sufficient planning resources are allocated to meet the LSE Coincident Peak Demand multiplied by one plus the PRM and one plus transmission losses. The submission of this forecast follows MISO's prescribed processes.

LSEs must report their peak demand forecasts for each month of the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years for the NERC MOD standards.

Forecasted demand in MISO reflects the expected "50/50" LSE Coincident Peak Demand and includes the effect of all distribution and transmission losses. This means there is a 50% chance that actual demand will be higher and a 50% chance that actual demand will be lower than the forecasted level.

LSEs must also report their Net Energy for Forecasted Demand for the same time periods: monthly for the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years for the NERC MOD standards.

LSEs register demand side management into the MECT tool separate from their demand forecasts. These resources are explicitly modeled on the supply side in determination of the PRM.

Resource Plan Requirements

LSEs are obligated to provide MISO with resource plans demonstrating that Zonal Resource Credits (ZRC) will be available to meet their resource adequacy requirements. Generally, the Planning Reserve Margin Requirement (PRMR) is the forecast LSE Peak Demand multiplied by one plus MISO PRM UCAP and one plus transmission losses, unless the state utility commission establishes a PRM that is different from MISO's. Additionally LSEs must meet a Local Clearing Requirement (LCR) for the Local Resource Zone (LRZ) for which the LSE resides, Vectren is in LRZ six. The LCR is equal to the Local Reliability Requirement (LRR) less the Capacity Import Limit (CIL) into that zone. The LRR is established so that the LRZ can also meet the 1 day in 10 LOLE reliability standard by clearing the necessary resources within the LRZ.

If a state utility commission establishes a minimum PRM for the LSEs under their jurisdiction, that state-set PRM will be adopted by MISO for affected LSEs in such state. If a state utility commission establishes a PRM that is higher than the MISO established PRM, the affected LSE's must meet the state-set PRM.[1] Indiana does not have a stated minimum planning reserve margin; therefore, Vectren must meet the PRM of MISO.

Qualification of Resources, Including Unforced Capacity Ratings (UCAP), Conversion of UCAP MW to Zonal Resource Credits

To comply with MISO Resource Adequacy provisions, LSEs must submit data for their eligible resources for MISO to determine the total installed capacity that the resource can reliably provide, called Unforced Capacity Rating (UCAP).

[1] From MISO BPM-011-r13 Resource Adequacy Section 3.5.5 State Authority to set PRM

MISO will calculate unforced capacity for all generation resources interconnected to the MISO Transmission System while respecting the interconnection study results and the results of the aggregate deliverability analysis.

The first step is to compare a Generation Resource Net Dependable Capacity (NDC) to the tested capacity from the interconnection process to determine the total installed capacity that the generation resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). A unit's NDC for the Planning Year is determined by averaging the NDC data that is entered into MISO's Generating Availability Data System (GADS) database. The UCAP rating represents the MW's that are eligible to be converted into ZRCs.

Evaluation and Reporting

MISO will maintain databases and will "..provide to states, upon request, with relevant resource adequacy information as available…" per section 69 of the MISO Tariff during relevant time periods, subject to the data confidentiality provisions in section 38.9 of the MISO Tariff.

Vectren's approach to the Voluntary Capacity Auction

Due to the long lead time generally required to build capacity resources, Vectren does not consider MISO's annual Planning Resource Auction an appropriate means to meet the needs of the 20 year Integrated Resource Plan and continues to pursue more traditional means of ensuring adequate resources.

Future of MISO's Module E

MISO proposed Capacity Market

MISO is currently evaluating whether the annual summer based resource adequacy construct contains gaps that prevent it from achieving resource adequacy during all periods of the year. MISO is working to identify seasonal or other changes that will close any identified gaps.

Footprint Changes

On Dec. 19, 2013 MISO began coordinating all RTO activities in the newly combined footprint consisting of all or parts of 15 states with the integration of the MISO south entities which include the LBAs of Entergy Arkansas, Inc., Entergy Texas, Inc., Entergy Mississippi, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., Entergy New Orleans, Inc., Cleco Power LLC, Lafayette Utilities System, Louisiana Energy & Power Authority, South Mississippi Electric Power Authority and Louisiana Generating, LLC.

DEMAND RESPONSE

Demand response is an integral part of a utility's system, operations, and planning, and helps Vectren meet the obligation to serve all customers. Effective July 1, 2011 and pursuant to Commission order in Cause 34566 MISO 4, Vectren filed Rider DR, which provides qualifying customers the optional opportunity to reduce their electric costs by participating in the MISO wholesale energy market. This rider helps the Company's efforts to preserve reliable electric service through customer provision of a load reduction during MISO high price periods and declared emergency events. This initial Rider DR offers two programs, Emergency Demand Response (EDR) and Demand Response Resource Type 1 ("DRR-1") energy programs.

MISO FORECAST

Based on analysis of load forecasts and planned resources derived from survey responses provided by the load serving entities in its footprint, MISO has created several iterations of resource adequacy forecasts that indicate beginning in 2016, several zones within the footprint may lack the capacity required to meet reserve requirements. MISO continues to assess the accuracy of this analysis and appears to concede that state regulatory commissions remain confident that adequate reserves exist in the near term. However, such studies do highlight the potential reliability issues created by the EPA emissions restrictions, and in particular, the potential for numerous base load coal plant retirements driven by the EPA's Clean Power Plan. Questions

regarding available capacity, as well as local reliability concerns will be factored into the Company's planning processes.

Vectren's Approach to Resource Adequacy

Vectren will continue to comply with MISO's Module E requirements, which includes the possibility for varying amounts of planning reserves.

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Chapter 4

ENVIRONMENTAL

INTRODUCTION

Compliance planning associated with existing and anticipated environmental laws and regulations in each of the three media (air, water and waste) is discussed in this chapter.

CURRENT ENVIRONMENTAL COMPLIANCE PROGRAMS:

AIR

Acid Rain Program

Vectren's Acid Rain compliance program was approved by the IURC in Cause No. 39347, which authorized the construction of a combined sulfur dioxide (SO_2) scrubber for FB Culley Units 2 and 3. As AB Brown Units 1 and 2 were newer vintage units, the units' original construction included scrubber technology. Vectren relies upon its existing scrubber technology for compliance with acid rain requirements and has sufficient allowance allocations to meet its future acid rain obligations. See, Table 4-1, a listing of current air pollution control devices for each Vectren unit, Table 4-2, a listing of emission rates for each Vectren unit, and Table 4-3 a listing of the acid rain allowances allocated to Vectren units.

Table 4-1 Air Pollution Control Devices Installed

	FB Culley 2	FB Culley 3	Warrick 4	AB Brown 1	AB Brown 2
Commercial Date	1966	1973	1970	1979	1986
MW (UCAP)	83	257	135	228	233
NO_X	Low NO_X Burner	SCR[1]	SCR	SCR	SCR
SO_2	FGD[2]	FGD	FGD	FGD	FGD
PM[3]	ESP[4]	FF[5]	ESP	FF	ESP

[1] Selective Catalytic Reduction
[2] Flue Gas Desulfurization
[3] Particulate Matter
[4] Electrostatic Precipitator
[5] Fabric Filter

Table 4-2 Current (2013) Emission Rates (lbs./mm Btu)

Units	SO_2	Annual NO_X	Ozone Season NO_X
AB Brown 1	0.6400	0.1510	0.1464
AB Brown 2	0.3610	0.1160	0.1091
AB Brown 3	0.0006	0.1800	0.1710
AB Brown 4	0.0006	0.0310	0.0214
FB Culley 2/3	0.1700	0.1190	0.1312
Warrick 4	0.1800	0.2400	0.2740
BAGS 2	0.0006	0.2226	0.2111

Table 4-3 SO2 Acid Rain Allowances Allocated to Vectren Units (per year)

Plant Name	Percent Ownership	2013	2014-2041
AB Brown	100%	10,546	10,546
FB Culley	100%	9,922	9,922
Warrick 4[1]	50%	5,122	5,122

For purposes of compliance year 2014, acid rain allowances will continue to be used for compliance with the SO_2 emission reductions requirements of the Clean Air Interstate Rule (CAIR). As detailed more fully below, the Cross-State Air Pollution Rule (CSAPR) which was originally slated to become effective in two phases during 2012 and 2014, was stayed by the Court in December 2011 and vacated in August 2012. Through a series of appeals, it was reviewed by the US Supreme Court who issued judgment on April 29, 2014 to reverse the lower Court decision and upheld CSAPR. The stay was lifted on October 23, 2014 but an implementation schedule and reallocation of allowances has not been determined at this time. Due to the timing of this recent decision, Vectren is unable to state when CSAPR will go into effect and what the final allowance levels will be for each of its units. Neither the CAIR rule nor CSAPR supersedes the Acid Rain program. Facilities will still be required to annually surrender acid rain allowances to cover emissions of SO_2 under the existing Acid Rain program.

[1] Number of allowances shown are for Vectren's portion of Warrick 4

NO_x SIP Call

Vectren's NO_x SIP Call compliance plan was approved by the IURC in Cause Nos. 41864 and 42248, which authorized Vectren to retrofit selective catalytic reduction (SCR) technology on Culley Unit 3, Warrick Unit 4, and Brown Units 1 and 2. Vectren relies upon its existing SCR technology for compliance with the seasonal NO_x reductions required in the NO_x SIP Call. When CAIR was finalized in March of 2005, the EPA included a seasonal NO_x emission reduction requirement, which incorporated, and in most cases, went beyond the seasonal NO_x emission reductions required under the NO_x SIP Call. For purposes of compliance year 2014, CAIR NO_x seasonal allowances will continue to be used for compliance with the seasonal NO_x emission reductions requirement under the current CAIR rule. CAIR and CSAPR are discussed more fully below.

CAIR and CSAPR

On March 10, 2005, the US Environmental Protection Agency (EPA) finalized its determination in the CAIR rule that emissions from coal-burning Electric Generating Units (EGUs) in certain upwind states result in the transport of fine particles ($PM_{2.5}$) and ozone that significantly contribute to nonattainment of the applicable ambient air quality standards for those pollutants in downwind states. The CAIR rule required revisions to state implementation plans in twenty eight states, including Indiana, requiring further reductions of NO_x and SO_2 from EGUs beyond those required in the NO_x SIP Call and Acid Rain programs. Emissions reductions under the CAIR rule were to be implemented in two phases, with requirements for first phase reductions in 2009 (NO_x) and 2010 (SO_2), and second phase reductions starting in 2015. The Warrick 4 scrubber was constructed to comply with the CAIR regulation and approved in Cause No. 42861. The CAIR rule provided a federal framework for a regional cap and trade system, and those allowances allocated to the Vectren units under the CAIR rule are being used for compliance in 2014 and until the EPA reinstates CSAPR (see below).

On July 6, 2010, the EPA proposed its Clean Air Transport Rule ("Transport Rule") in response to the court's remand of CAIR. In an effort to address the court's finding that CAIR did not adequately ensure attainment of ozone and $PM_{2.5}$ air quality standards in certain Eastern states due to unlimited trading and banking of allowances, the Transport Rule proposal dramatically reduced the ability of facilities to meet the required emission reductions through interstate allowance trading. Like CAIR, the Transport Rule proposal set individual state caps for SO_2 and NO_x; however, unlike CAIR, individual unit allowance allocations were set out directly in the Transport Rule proposal. Interstate allowance trading was severely restricted and limited to trading within a zonal group. On July 7, 2011, the EPA finalized the Transport Rule proposal and renamed the program the Cross State Air Pollution Rule (CSAPR). CSAPR sets individual allowance allocations for Vectren's units directly in the rule. Table 4-4 shows a listing of individual unit allowance allocations under the original CSAPR. Under the original version of CSAPR, any excess CAIR allowances (vintage 2011 or older) that were not needed for compliance in 2011 could not be used for compliance with CSAPR, which was scheduled to become effective January 1, 2012. It is not yet known how, or when, the EPA will revise the effective dates in the reinstated version of the rule. Given the stringent state emission caps, the limited allowance trading available under the CSAPR, and the unknown implementation timing due to the recent lifting of the court ordered stay on October 23, 2014 it is virtually impossible to predict with any certainty the availability of excess allowances for compliance and the costs of those allowances under a reinstated CSAPR.

Table 4-4 CSAPR Allowances Allocated to Vectren Units

	SO_2 Allocation		Annual NO_X		Seasonal NO_X	
	2012	**2014**	**2012**	**2014**	**2012**	**2014**
AB Brown 1	3,761	2,080	1,393	1,376	595	586
AB Brown 2	3,889	2,151	1,440	1,422	601	591
AB Brown 3	1	1	19	19	14	14
AB Brown 4	0	0	6	6	4	4
BAGS 2	0	0	26	26	18	8
FB Culley 2	1,488	925	619	612	268	264
FB Culley 3	2,923	2,799	1,874	1,851	792	780
Warrick 4	2,802	1,550	1,037	1,025	444	437

Vectren's original multi-pollutant compliance plan was approved under IURC Cause No. 42861. While Vectren's original multi-pollutant planning focused on compliance with the CAIR regulation which was in place at the time, the successful execution of the approved multi-pollutant plan would enable Vectren to comply with the SO_2 and NO_x emission caps in the original CSAPR allocation without further significant capital investment; however, while currently well controlled, Vectren will incur increased Operating and Maintenance (O&M) costs attributable to a new regulation, such as an increase in chemical costs to achieve the lower emission targets. With the completion of the Warrick 4 scrubber pursuant to the approved order in Vectren's multi-pollutant proceeding, Vectren's generating system is 100% scrubbed for SO_2 and has selective catalytic reduction technology on all but one unit (FB Culley Unit 2). See Table 4-1. As such, Vectren will be well-positioned to comply with the new, more stringent SO_2 and NO_x caps that are required by a re-instated CSAPR, without reliance on a highly uncertain allowance market or further significant capital expenditures. It is important to note that CSAPR stay was just recently lifted on October 23, 2014, and final implementation dates are still unknown.

Mercury and Air Toxics Rule

The 1990 Amendments to the Clean Air Act (CAA or Act) required that the EPA determine whether EGUs should be required to reduce hazardous air pollutants, including mercury, under § 112 of the Act. In December of 2000, the EPA officially listed coal-fired EGUs as subject to CAA § 112 Maximum Achievable Control Technology (MACT) Standards for mercury, thus lifting a previous exemption from the air toxics requirements. On March 15, 2005, the EPA finalized its Clean Air Mercury Rule (CAMR) which set "standards of performance" under CAA §111 for new and existing coal-fired EGUs and created a nation-wide mercury emission allowance cap and trade system for existing EGUs which sought to reduce utility emissions of mercury in two phases. The first phase cap would have started in 2010, except the CAMR rule was similarly vacated by a reviewing court in March of 2008. Thus, like the CAIR rule, utilities were preparing for compliance with a finalized CAMR regulation that was ultimately found to be deficient by a reviewing court. The reviewing court directed the EPA to proceed with a MACT rulemaking under CAA § 112 which would impose more stringent individual plant-wide limits on mercury emissions and not provide for allowance trading.

On March 16, 2011, the EPA released its proposed MACT for utility boilers. The final rule, known as the Mercury and Air Toxics Standards (MATS) was published in the Federal Register on February 16, 2012. The rule sets plant-wide emission limits for the following hazardous air pollutants (HAPs): mercury, non-mercury HAPs (e.g. arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The EPA established stringent plant-wide mercury emission limits (1.2 lb/TBtu for individual unit or 1.0 lb/TBtu for plant average) and set surrogate limits for non-mercury HAPs (total particulate matter limit of .03 lb/MMBtu) and acid gases (HCL limit of .002 lb/MMBtu). The surrogate limits can be used instead of individual limits for each HAP. Compliance with the new limits will be required by April 16, 2015. The Indiana Department of Environmental Management (IDEM), the state permitting authority, has the discretion to grant a compliance extension of up to

one year on a case by case basis if a source is unable to install emission controls or make fuel conversions prior to the April 2015 deadline. Vectren was granted a 1-year extension for the AB Brown Unit 2, contingent upon the need for injection of a secondary mercury treatment chemical. The need for the secondary chemical will not be known until after the primary system is operational at the end of 2014. Vectren currently has a MATS Compliance plan before the Commission (IURC Cause 44446) for approval that includes organo sulfide injection at the baseload units (AB Brown 1, AB Brown 2, FB Culley 3, and Warrick 4) with the possibility of an additional HBr injection at AB Brown 2 if needed.

SOLID WASTE DISPOSAL

Scrubber by-products from AB Brown are sent to an on-site landfill permitted by IDEM. During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren generated fly ash. Since February 2010, the majority of AB Brown fly ash has been diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri, via a river barge loader and conveyor system. The remainder of the A B Brown fly ash and bottom ash is sluiced to an on-site pond. This major sustainability project will serve to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal. The majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and transported offsite for recycling into a cement application.

Fly ash from the FB Culley facility is similarly transported off-site for beneficial reuse in cement. Until mid-2009, fly ash from the FB Culley facility was sent to the Cypress Creek Mine for backfill pursuant to the mine's surface coal mine permit. In May 2009, FB Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the AB Brown facility in late 2009, FB Culley's fly ash is now transported to the AB Brown loading facility and shipped to the cement plant via

river barge. The FB Culley facility sends its bottom ash to one of two on-site ponds via wet sluicing. The ponds are seven and eighteen acres in size. Scrubber by-product generated by the FB Culley facility is also used for beneficial reuse and shipped by river barge from FB Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site, but is being recycled and shipped off-site for beneficial reuse.

HAZARDOUS WASTE DISPOSAL

Vectren's AB Brown and FB Culley plants are episodic producers of hazardous waste that may include paints, parts washer fluids, or and other excess or outdated chemicals. Both facilities are typically classified as Conditionally Exempt Small Quantity Generators.

WATER

AB Brown and FB Culley currently discharges process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the IDEM. AB Brown utilizes cooling towers while FB Culley has a once through cooling water system.

The Ohio River Valley Sanitation Commission (ORSANCO) regional water quality standards were most recently revised in 2012 and are more restrictive than current EPA standards. ORSANCO is a regional state compact focused on water quality issues for the Ohio River and governs water discharges that enter the Ohio River. Under Vectren's most recent NPDES permits issued in late 2011, Vectren must meet more restrictive mercury limits at its river outfall to comply with the ORSANCO mercury limit of 12 ppt monthly average. To meet the limits, Vectren chose to install two chemical-precipitation water treatment systems at AB Brown and one at FB Culley. The new water treatment systems are included in the pending environmental compliance proceeding before the IURC (Cause No. 44446), and began operation in third quarter 2014.

FUTURE ENVIRONMENTAL REGULATIONS

CARBON REGULATION

On June 2, 2014, the EPA issued the CAA Section 111(d) Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for existing sources, known as the Clean Power Plan (CPP). The CPP sets state-specific carbon reduction goals based on a state's existing generation mix and provides guidelines for the development, submission and implementation of state plans to achieve the state goals. The EPA asserts that the state reduction goals will result in a 30% decrease in CO_2 emissions from 2005 levels by 2030. To insure each state is making adequate progress towards the 2030 goal, an interim emission rate goal for 2020-2029 has also been established.

Indiana's state specific emission rate goals are 1,607 lb CO_2/MWh for the interim period and 1,531 lb CO_2/MWh for a final goal. This equates to a 20% reduction in CO_2 emission rates from 2012 levels. The EPA determined the state specific goals through a portfolio approach that includes improving power plant heat rates, dispatching lower emitting fuel sources more frequently and increasing utilization of renewable energy sources and energy efficiency programs. Specifically, each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA has determined are achievable by that state.

The four building blocks used by the EPA to calculate state goals are as follows:

1) Coal fleet heat rate improvement of 6%.
2) Increased dispatch of existing baseload natural gas generation sources to 70%. For Indiana this also includes announced new natural gas combined cycle plants.
3) Renewable energy portfolio of 5% in the interim and 7% in the final stage.
4) Energy efficiency reductions of 1.5% annually starting in 2020.

While individual state goals were based on the EPA's application of the building blocks to 2012 emission rates, states have flexibility through their state implementation plan to

implement the building blocks in part or not at all to reach the listed goal, or enter a regional trading program. Since the state plan may include a variety of options, many of which are outside the fence line and control of a power plant, the interim and final CO_2 emission rates will not necessarily apply to individual generating plants or companies within the state. It is yet to be determined how the CPP will directly affect Vectren's generating units.

The final rule is scheduled for June 2015, with individual state implementation plans due by June 2016. States have the option to seek a one year extension, or up to two years if part of a regional or multi-state plan. After the submittal of the state or regional plan, the first annual reporting begins in 2022. This timeline represents the earliest emission reductions will be required, as it is almost certain that this rule will be heavily litigated. Vectren will continue to work with the state of Indiana to ensure that the State's compliance plan is the least cost to Indiana consumers.

WASTE DISPOSAL

Over the course of the last twenty years the EPA has conducted numerous studies and issued two reports to Congress on the management of coal combustion by-products (primarily fly ash, bottom ash, and scrubber by-product), concluding both times that these materials generally do not exhibit hazardous waste characteristics and can be managed properly under state solid waste regulations. In response to the Tennessee Valley Authority's (TVA's) catastrophic ash pond spill in December of 2008, the EPA revisited its regulatory options for the management of coal combustion by-products. On June 21, 2010, the EPA published three options for a proposed rule covering Coal Combustion Residuals (CCRs). Two options would regulate combustion by-products as solid waste under the Resource Conservation and Recovery Act (RCRA) Subtitle D, with the only significant difference being whether existing ponds are retrofitted or closed within five years, or whether utilities will be permitted to continue to use an existing pond for its remaining useful life. The third option would regulate combustion by-products as hazardous waste under RCRA Subtitle C. Under all three options, certain beneficial re-

uses of coal combustion residuals, such as cement and wallboard applications, will continue to be allowed. The EPA has set December 19, 2014 as the deadline for issuing the final rule.

Uncertainties remain until the rule is finalized. For example, under the Subtitle D proposed rule, unlined ash ponds would have to be closed within five years and groundwater monitoring installed within one year. The proposal, however, did not define whether the term “close” means to cease receiving new material or to have the site completely capped and grass covered within five years. The proposal also failed to take into account site specific circumstances such as size of the pond and the percentage filled when establishing the five year closure timeframe. A majority of the final closure obligation and compliance costs will be focused on historic material that is already in the ponds so a change in future generation will not negate the obligation to comply with the CCR regulation when it is issued. However, as a result of Vectren’s previous investments in dry fly ash handling and beneficial reuse activities, the volume of new material added to the ponds since 2009 has been significantly decreased.

As a direct result of the TVA spill referenced above, the EPA undertook to inspect all surface impoundments and dams holding combustion by-products. The EPA conducted site assessments at Vectren's AB Brown and FB Culley facilities and found the facilities' surface impoundments to be satisfactory and not posing a high hazard.

WATER

There are multiple regulatory rulemakings that could, when finalized, require more stringent limits for power plant discharges.

The EPA is developing new Effluent Limit Guidelines and Standards (ELGS) for the Steam Electric Power Generating Point Source Category. A draft was issued June 7, 2013, with a final rule scheduled for September 2015. The draft rule requested comment on 8 different options for treatment standards and compliance locations that ranged from no change of

current standards to a requirement for full zero liquid discharge. Of the eight options, the EPA identified four "preferred" options. For the preferred options, the size of Vectren's units would drop the plants out of the requirement for specific treatment and discharge limits for Flue Gas Desulfurization (FGD) waste water or bottom ash transport water in 2 of the 4 options. Instead, IDEM would apply Best Professional Judgment (BPJ) which takes into consideration site specific factors. While Vectren acknowledges that the EPA's final ELGs could further alter discharge parameters and limits, it is not possible at this time to predict the outcome of the final rule. Vectren believes its chosen treatment systems are the most cost effective option for meeting its current permits while limiting potential stranded costs when new regulations take effect.

The EPA released its final rule regulating cooling water structures under Section 316(b) of the Clean Water Act (CWA) on August 15, 2014. Section 316(b) requires that intake structures that withdraw > 2 MGD of water, including most electric generating units, use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a water body. The rule lists separate sampling and study programs to minimize entrainment (pulling small organisms into the intake structure) and impingement (trapping or pinning fish against the exterior of the intake structure). In addition, three additional studies are required that look at technical feasibility and treatment costs, cost benefits evaluation, and non-water quality environmental impacts of the potential treatment option. These studies, combined with the results of the in-river fish sampling will help determine potential treatment options.

Seven options were identified as pre-approved methods for complying with impingement mortality standards. While cooling towers are listed as an option, they are not mandated for existing facilities. Vectren does not believe cooling tower retrofits will be required at FB Culley due to its size and location on the Ohio River. The EPA acknowledges that for many facilities, the process of conducting the studies, determining the best treatment option, constructing the selected option, and confirming the adequacy of the treatment may take a minimum of 8 years from the time the rule

becomes effective. Vectren's FB Culley units currently use a "once through" cooling water intake system and are affected by this proposed regulation. Vectren's AB Brown units use a closed cooling water system. However, under the final rule Vectren would still be required to submit documentation and study reports to confirm the existing cooling water tower mitigates impingement and entrainment.

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CHAPTER 5

SALES & DEMAND FORECAST

INTRODUCTION

The electric energy and demand forecasts provide the basis for evaluation of supply-side and demand-side options to meet the electric needs of Vectren's customers. These forecasts reflect local and regional economic impacts, the effects of past, present, and proposed Demand Side Management / Demand Response (DSM/DR) programs, mandated efficiency standards, and the effects of normal market forces on electricity sales.

Overview of Vectren's Customers

Vectren provides delivery services to approximately 142,000 electric residential, general service (commercial), and large (primarily industrial) customers with electricity in southwestern Indiana. A high proportion of Vectren's sales are made to electric-intensive general service and large customers. In 2013, about 29% of Vectren's annual retail electric energy sales were consumed by residential customers, 23% of sales were consumed by General Service (GS), and 48% of sales were consumed by more than 100 large customers. Less than 1% served other load (street lights). Significant general service and large load creates complexity in load forecasting. These customers have the ability to significantly impact Vectren's demand for electricity, as economic factors affect their businesses' success.

ELECTRIC LOAD FORECAST OVERVIEW

Vectren developed low, base, and high forecasts of annual energy sales and requirements (e.g. sales plus related delivery losses) and peak loads (e.g. demand plus losses) for the purposes of its IRP. These forecasts, and the activities undertaken to develop them, are described in this section.

Development of the Vectren system-wide long-term electric load forecast involves the aggregation of multiple models. Vectren uses statistically adjusted end use (SAE) modeling and econometric modeling to forecast customer needs for the future. Vectren has investigated the use of pure end-use modeling for forecasting purposes but

believes that a combination of statistically adjusted end-use and econometric modeling best accommodates its forecasting needs. End-use modeling involves building and maintaining a detailed end-use database to capture appliance and thermal shell characteristics, as well as end-use consumption information. The basic structure of an end-use model is households multiplied by appliance saturation and unit energy consumption. Each component of the end-use model is modeled separately. For these reasons, end-use modeling is very expensive to develop and maintain. It is meant primarily for long-term modeling (5-20 years). Often, a separate short term forecast is necessary, which is hard to integrate with the long-term forecast. Vectren utilizes statistically adjusted end-use models to forecast residential and general service loads. Large customer needs are forecasted with an econometric linear regression model, while street lighting load is forecasted with a simple trend model. The detail of Vectren's forecasting methodology is discussed later in this chapter.

FORECAST RESULTS

The base case forecasts of annual energy requirements and peak loads for the 2014 - 2034 planning period are provided in Tables 5-1 and 5-2. Annual energy requirements are projected to have a -.2% compound annual growth rate over the twenty year planning period. Peak requirements are projected to have a compound annual growth rate of -.1% over the twenty year planning period.

Table 5-1 Base Case Energy and Demand Forecast

Year	Peak (MW)[1]	Annual Energy (GWh)
2014 Proj.	1,145	5,782
2015	1,155	5,914
2016	1,156	5,936
2017	1,113	5,514
2018	1,109	5,503
2019	1,106	5,494
2020	1,106	5,497
2021	1,106	5,492
2022	1,107	5,494
2023	1,107	5,494
2024	1,107	5,496
2025	1,106	5,487
2026	1,106	5,487
2027	1,107	5,492
2028	1,109	5,507
2029	1,110	5,509
2030	1,111	5,517
2031	1,111	5,523
2032	1,113	5,540
2033	1,114	5,548
2034	1,115	5,560
Compound Annual Growth Rate, 2014-2034 Including Wholesale	-0.1%	-0.2%

[1] Includes wholesale contract sales for 2014

Table 5-2 Base Case Energy Forecast by Customer Class

Year	Residential (GWh)	General Service (GWh)	Large (GWh)	Other (GWh)	Net DSM (GWh)	DG (GWh)	Wholesale (GWh)	Losses (GWh)	Total Requirements (GWh)
2013 Calendar	1,435	1,294	2,744	21			61	267	5,822
2014 Proj.	1,444	1,300	2,739	20	(47)	(1)	61	265	5,782
2015	1,444	1,327	2,926	20	(72)	(1)	0	271	5,914
2016	1,448	1,351	2,945	20	(98)	(2)	0	272	5,936
2017	1,451	1,354	2,563	19	(123)	(3)	0	253	5,514
2018	1,458	1,357	2,567	19	(148)	(3)	0	252	5,503
2019	1,469	1,363	2,569	19	(173)	(5)	0	252	5,494
2020	1,475	1,370	2,574	19	(186)	(7)	0	252	5,497
2021	1,480	1,373	2,577	19	(199)	(9)	0	252	5,492
2022	1,490	1,380	2,579	19	(211)	(12)	0	252	5,494
2023	1,500	1,386	2,579	18	(224)	(17)	0	252	5,494
2024	1,514	1,395	2,578	18	(237)	(23)	0	252	5,496
2025	1,523	1,398	2,579	18	(250)	(32)	0	251	5,487
2026	1,534	1,404	2,579	18	(263)	(37)	0	251	5,487
2027	1,547	1,413	2,581	18	(276)	(42)	0	252	5,492
2028	1,562	1,427	2,584	18	(289)	(48)	0	252	5,507
2029	1,572	1,436	2,588	18	(302)	(55)	0	252	5,509
2030	1,586	1,445	2,593	18	(316)	(62)	0	253	5,517
2031	1,599	1,455	2,598	18	(329)	(71)	0	253	5,523
2032	1,616	1,473	2,604	18	(343)	(81)	0	254	5,540
2033	1,628	1,486	2,611	18	(356)	(93)	0	254	5,548
2034	1,644	1,501	2,619	18	(370)	(106)	0	255	5,560
Compound Annual Growth Rate for (2014-2034)	0.6%	0.7%	-0.2%	-0.7%					-0.2%

Low and high energy and demand forecasts were developed by modifying the assumptions around conservation, distributed generation adoption, economic drivers, population projections, and large customer additions. The difference between the two high growth cases is slow steady growth or a large step up. In the high growth (modeled) forecast, economic growth was increased from approximately 1% to 2%, and population growth was increased from about .3% to .5%. The high growth (large load) case is the same as the base case, with the addition of a large customer in 2018. The results are shown in Table 5-3 and 5-4.

Table 5-3 Base, Low, and High Case Energy Forecasts

Year	Base Annual Requirements		Low Growth Annual Requirements		High Growth (modeled) Annual Requirements		High Growth (large load) Annual Requirements	
	GWh	Growth,%	GWh	Growth,%	GWh	Growth,%	GWh	Growth,%
2014 Proj.	5,782		5,782		5,799		5,782	
2015	5,914	2.3%	5,907	2.2%	5,947	2.6%	5,914	2.3%
2016	5,936	0.4%	5,922	0.3%	5,990	0.7%	5,936	0.4%
2017	5,514	-7.1%	5,320	-10.2%	5,609	-6.4%	5,514	-7.1%
2018	5,503	-0.2%	5,302	-0.3%	5,645	0.6%	6,098	10.6%
2019	5,494	-0.2%	5,287	-0.3%	5,681	0.6%	6,088	-0.2%
2020	5,497	0.1%	5,290	0.1%	5,712	0.5%	6,090	0.0%
2021	5,492	-0.1%	5,285	-0.1%	5,734	0.4%	6,085	-0.1%
2022	5,494	0.0%	5,286	0.0%	5,764	0.5%	6,087	0.0%
2023	5,494	0.0%	5,284	0.0%	5,799	0.6%	6,085	0.0%
2024	5,496	0.1%	5,285	0.0%	5,841	0.7%	6,088	0.0%
2025	5,487	-0.2%	5,273	-0.2%	5,870	0.5%	6,077	-0.2%
2026	5,487	0.0%	5,272	0.0%	5,909	0.7%	6,077	0.0%
2027	5,492	0.1%	5,276	0.1%	5,950	0.7%	6,081	0.1%
2028	5,507	0.3%	5,288	0.2%	5,997	0.8%	6,095	0.2%
2029	5,509	0.1%	5,289	0.0%	6,028	0.5%	6,097	0.0%
2030	5,517	0.1%	5,293	0.1%	6,060	0.5%	6,104	0.1%
2031	5,523	0.1%	5,296	0.0%	6,094	0.6%	6,109	0.1%
2032	5,540	0.3%	5,310	0.3%	6,132	0.6%	6,127	0.3%
2033	5,548	0.1%	5,312	0.0%	6,157	0.4%	6,133	0.1%
2034	5,560	0.2%	5,320	0.1%	6,188	0.5%	6,145	0.2%
Compound Annual Growth Rate for (2014-2034)		-0.2%		-0.4%		0.3%		0.3%

Table 5-4 Base, Low, and High Case Demand Forecasts

Year	Base Annual Requirements		Low Growth Annual Requirements		High Growth (modeled) Annual Requirements		High Growth (large load) Annual Requirements	
	MW	Growth,%	MW	Growth,%	MW	Growth,%	MW	Growth,%
2014 Proj.	1,145		1,145		1,148		1,145	
2015	1,155	0.8%	1,153	0.7%	1,160	1.0%	1,155	0.8%
2016	1,156	0.1%	1,153	-0.1%	1,164	0.3%	1,156	0.1%
2017	1,113	-3.7%	1,088	-5.6%	1,127	-3.2%	1,113	-3.7%
2018	1,109	-0.3%	1,083	-0.5%	1,130	0.3%	1,208	8.6%
2019	1,106	-0.3%	1,079	-0.4%	1,133	0.3%	1,205	-0.3%
2020	1,106	0.0%	1,079	0.0%	1,136	0.3%	1,206	0.0%
2021	1,106	0.0%	1,079	0.0%	1,139	0.3%	1,206	0.0%
2022	1,107	0.1%	1,080	0.0%	1,143	0.3%	1,206	0.0%
2023	1,107	0.0%	1,079	0.0%	1,147	0.4%	1,206	0.0%
2024	1,107	0.0%	1,079	0.0%	1,152	0.4%	1,206	0.0%
2025	1,106	-0.1%	1,077	-0.2%	1,155	0.3%	1,205	-0.1%
2026	1,106	0.0%	1,077	0.0%	1,160	0.4%	1,205	0.0%
2027	1,107	0.1%	1,078	0.1%	1,165	0.4%	1,206	0.1%
2028	1,109	0.2%	1,079	0.1%	1,171	0.5%	1,207	0.1%
2029	1,110	0.1%	1,079	0.0%	1,175	0.3%	1,208	0.0%
2030	1,111	0.1%	1,080	0.0%	1,179	0.3%	1,209	0.1%
2031	1,111	0.0%	1,080	0.0%	1,183	0.3%	1,209	0.0%
2032	1,113	0.2%	1,081	0.1%	1,187	0.4%	1,211	0.1%
2033	1,114	0.1%	1,081	0.0%	1,190	0.2%	1,211	0.1%
2034	1,115	0.1%	1,081	0.0%	1,193	0.3%	1,212	0.1%
Compound Annual Growth Rate for (2014-2034)		-0.1%		-0.3%		0.2%		0.3%

FORECAST INPUTS & METHODOLOGY

Forecast Inputs

Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database contains detailed customer information including rate, service, North American Industrial Classification System (NAICS) codes (if applicable), usage, and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana, and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, GS, and large sales.

Weather Data

The daily maximum and minimum temperatures for Evansville, IN were obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. NOAA data is used to calculate monthly heating degree days (HDD) and cooling degree days (CDD). HDDs are defined as the number of degrees below the base temperature of 65 degrees Fahrenheit for a given day. CDDs are defined as the number of degrees above the base temperature of 65 degrees Fahrenheit for a given day. HDDs and CDDs are averaged on a monthly basis. Normal degree days, as obtained from NOAA,

are based on a thirty year period. Historical weather data[1] is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. Note that in 2013 an appliance survey of Vectren's residential customers was conducted to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory.

Model Overview

Changes in economic conditions, prices, weather conditions, as well as appliance saturation and efficiency trends drive energy deliveries and demand through a set of monthly customer class sales forecast models. Monthly regression models are estimated for each of the following primary revenue classes:

- Residential (residential average usage and customer models)
- General Service
- Large
- Street Lighting

In the long-term, both economics and structural changes drive energy and demand growth. Structural changes are captured in the residential average use and general service sales forecast models through Statistically Adjusted End-Use (SAE) model specifications. The SAE model variables explicitly incorporate end-use saturation and

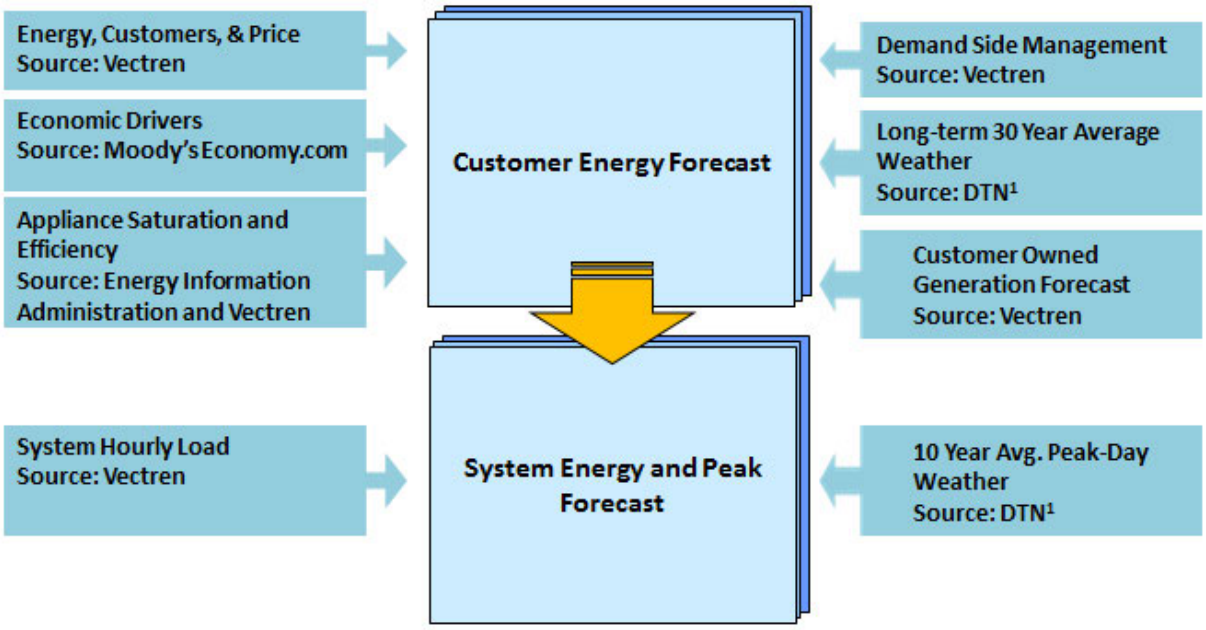
[1] The large sales model also includes CDDs.

efficiency projections, as well as changes in population, economic conditions, price, and weather. End-use efficiency projections include the expected impact of new end-use standards and naturally occurring efficiency gains. The large sales forecast is derived using an econometric model that relates large sales mostly to regional manufacturing Gross Domestic Product (GDP) growth. Street light sales are forecasted using a simple trend and seasonal model. The results of the sales forecast modes are imported into the demand forecast model.

The long-term demand forecast is developed using a "build-up" approach. This approach entails first estimating class and end-use energy requirements and then using class and end-use sales projections to drive system peak demand. The forecast models capture not only economic activity and population projections, but also expected weather conditions, the impact of improving end-use efficiency and standards, and electricity prices.

The long-term system peak forecast is derived through a monthly peak linear regression model that relates monthly peak demand to heating, cooling, and base load requirements. The model variables incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models as well as peak-day weather conditions. Note that the forecast is adjusted to reflect future Vectren sponsored DSM impacts, expected adoption of customer owned distributed generation, and expected large customer additions. Figure 5-1 shows the general approach.

Figure 5-1: Forecast Approach



[1] Formerly Data Transmission Network, now known as DTN

Analytic Methodology Used in Forecast

Residential Average Use Model

Residential customer usage is a product of heating, cooling, and other load. Both heating and cooling are weather sensitive and must be weather normalized in a model to remove weather noise from projections. Other major drivers of load are historical and projected market saturation of electronics, appliances, and equipment and their respective efficiencies. Vectren's service territory has a high saturation rate of central air conditioning equipment that is growing at a very slow pace, which helps to minimize average use growth. As equipment wears out and is replaced with newer, more efficient equipment, the average energy use per customer (AUPC) is reduced. Although there is increasing use of household electronics and appliances, this is balanced by increasing efficiencies in these areas. High tech devices like televisions, computers, and set-top boxes will see improving efficiencies, driven by innovation, competition, and voluntary agreements like the Energy Star program. Changes in lighting standards are having a large impact on energy consumption and will continue to impact residential customer usage in the years to come.

Even before Vectren sponsored DSM program savings, use per customer is largely flat, increasing only by 0.2% annually through 2024. This is largely due to the continuing phase-out of the most common types of incandescent light bulbs mandated by the Energy Independence and Security Act (EISA) and new end-use efficiency standards recently put in place by the Department of Energy (DOE). Average use begins to increase at a slightly faster rate in the later years, as the Energy Information Administration (EIA) baseline intensity projections only include those end-use standards that are currently law. Note that DOE continues to propose new energy efficiency standards.

The price of electricity and household income also influence average customer energy use. In general, there is a positive correlation between household income and usage. As household income rises, total usage rises. Conversely, there is a negative correlation between price and usage. As price goes up, average use goes down. Finally, the size of the home (number of inhabitants and square footage) and the thermal integrity of the structure affect residential consumption.

The residential average use model is a statistically adjusted end-use (SAE) model that addresses each of the previously discussed drivers of residential usage. SAE models incorporate many of the benefits of econometric models and traditional end-use models, while minimizing the disadvantages of each.

SAE models are ideal for identifying sales trends for short-term and long-term forecasting. They capture a wide variety of relevant data, including economic trends, equipment saturations and efficiencies, weather, and housing characteristics. Additionally, SAE models are cost effective and are easy to maintain and update. In the SAE model, use is defined by three primary end uses: heating (XHeat), cooling (XCool), and other (XOther). XHeat, XCool, and XOther are explanatory variables in the model

that explain customer usage. By design, the SAE model calibrates results into actual sales.

$$ResAvgUse_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + \varepsilon_m$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$$XHeat = HeatUse \times HeatIndex$$

Where

$$HeatUse = f(HDD, Household\ Income, Household\ Size, Price)$$

$$HeatIndex = g(Heating\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

The cooling variable is defined as:

$$XCool = CoolUse \times CoolIndex$$

Where

$$CoolUse = f(CDD, Household\ Income, Household\ Size, Price)$$

$$CoolIndex = g(Cooling\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

XOther captures non-weather sensitive end-uses:

$$XOther = OtherUse \times OtherIndex$$

Where

$$OtherUse = f(Seasonal\ Use\ Pattern, Household\ Income, Household\ Size, Price)$$

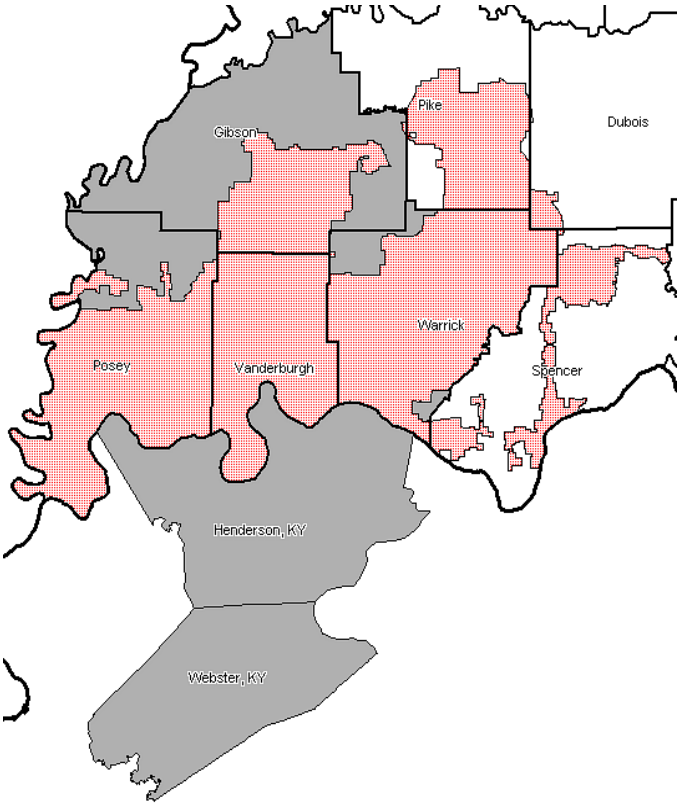
$$OtherIndex = g(Other\ Appliance\ Saturation\ and\ Efficiency\ Trends)$$

Monthly residential usage was regressed on the XHeat, XCool, and XOther variables. The average use model is estimated over the period January 2003 through December 2013. The model explains historical average use well with an Adjusted R^2 of 0.95 and in-sample MAPE of 3.3%.

Residential Customers Model

A simple linear regression model was used to predict the number of residential customers. The number of residential customers was forecasted as a function of population projections for the Evansville Metropolitan Statistical Area (MSA) from Moody's Economy.com. There is a strong correlation between the number of customers and population.

Figure 5-2 Vectren Service Territory Map



The Evansville MSA is a good proxy for the Vectren service territory. Figure 5-2 shows Vectren's service territory (in red) and the Evansville MSA in gray. The number of residential customers is projected to grow an average of .27% per year throughout the planning period. The adjusted R^2 for this model was .992, while the MAPE was .09%.

General Service (GS) Sales Model

Like the residential model, the general service (commercial) SAE sales model expresses monthly sales as a function of XHeat, XCool, and XOther. The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use efficiency improvements, with non-manufacturing output (GDP) and employment (ComVarm), real price (Pricem), and monthly HDD and CDD:

$$XHeat_m = EI_{heat} \times Price_m^{-0.10} \times ComVar_m \times HDD_m$$
$$XCool_m = EI_{cool} \times Price_m^{-0.10} \times ComVar_m \times CDD_m$$
$$XOther_m = EI_{other} \times Price_m^{-0.10} \times ComVar_m$$

The coefficients on price are imposed short-term price elasticities. A monthly forecast sales model is then estimated as:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + e_m$$

Commercial Economic Driver

Output and employment are combined through a weighted economic variable where ComVar is defined as:

$$ComVar_m = (ComEmploy_m^{0.5}) \times (ComOutput_m^{0.5})$$

Employment and nonmanufacturing output are weighted equally. The weights were determined by evaluating the in-sample and out-of-sample model statistics for different sets of employment and output weights.

The resulting commercial sales model performs well with an Adjusted R^2 of 0.95 and an in-sample MAPE of 2.2%.

Commercial sales growth averages 1.9% per year through 2016, as economic growth projections are relatively strong through this period. Real output is projected to increase at 2.2% with employment increasing 1.9%. After 2016, both output and employment growth slow with output averaging 0.5% growth and employment largely flat through 2024. Commercial sales, in turn, slow averaging 0.4% annually between 2016 and 2024.

Large Sales Model

The industrial sales forecast is based on a generalized monthly regression model where industrial sales are specified as a function of manufacturing employment, output, monthly CDD, and monthly binaries to capture seasonal load variation and shifts in the data. The economic driver is a weighted combination of real manufacturing output and manufacturing employment. The industrial economic (IndVar) variable is defined as:

$$IndVar_m = (ManufEmploy_m^{0.3}) \times (ManufOutput_m^{0.7})$$

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The final model's Adjusted R^2 is 0.65 with in-sample MAPE of 6.7%. The relatively low Adjusted R^2 and relatively high MAPE are due to the "noisy" nature of industrial monthly billing data.

There are many variables that impact large customer consumption that are not easily forecasted. These unforeseeable impacts make forecasting GS and large customers' usage with a high degree of certainty very difficult, as these customers' usage is extremely sensitive to economic conditions.

Lighting Sales Model

Street light sales are fitted with a simple seasonal exponential smoothing model with a trend term. Street lighting sales have been declining and are expected to continue to

decline through the forecast period as increasing lamp efficiency outpaces installation of new street lights. The model yielded an adjusted R^2 of .769 and a MAPE of 5.34%.

Vectren's total energy requirements include forecasted sales for the four sectors described above, wholesale contracts, DSM savings, impact of customer owned distributed generation (DG) and delivery losses. Losses were estimated to be approximately 4.8 percent of requirements. DSM savings and a forecast of customer owned DG are highlighted separately in the sales forecast, and the DSM programs are discussed in detail in Chapter 8 DSM Resources.

Peak Demand Forecast

The Vectren energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the monthly calendarized sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (unaccounted for energy). Monthly adjustment factors are calculated as the average monthly ratio of energy to sales.

The long-term system peak forecast is derived through a monthly peak linear regression model that relates monthly peak demand to heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

The model variables (HeatVarm, CoolVarm, and BaseVarm) incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models, as well as peak-day weather conditions.

Heating and Cooling Model Variables

Heating and cooling requirements are driven by customer growth, economic activity, changes in end-use saturation, and improving end-use efficiency. These factors are

captured in the class sales forecast models. The composition of the models allows historical and forecasted heating and cooling load requirement to be estimated.

The estimated model coefficients for the heating (XHeat) and cooling variables (XCool) combined with heating and cooling variable for normal weather conditions (NrmXHeat and NrmXCool) gives an estimate of the monthly heating and cooling load requirements. Heating requirements are calculated as:

$$HeatLoad_m = B_1 \times ResNrmXHeat_m + C_1 \times ComNrmXheat_m$$

B1 and C1 are the coefficients on XHeat in the residential and commercial models.

Cooling requirements are estimated in a similar manner. As there is a small amount of cooling in the industrial sector, industrial cooling is included by multiplying the industrial model coefficient for the CDD variable by normal monthly CDD. Cooling requirements are calculated as:

$$CoolLoad_m = B_2 \times ResNrmXCool_m \mid C_2 \times ComNrmXCool_m \mid D_2 \times NrmCDD_m$$

B2 and C2 are the coefficients on XCool in the residential and commercial models and D2 is the coefficient on CDD in the industrial sales model.

The impact of peak-day weather conditions is captured by interacting peak-day HDD and CDD with monthly heating and cooling load requirements indexed to a base year (2005). The peak model heating and cooling variables are calculated as:

$$HeatVar_m = HeatLoadIdx_m \times PkHDD_m$$
$$CoolVar_m = CoolLoadIdx_m \times PkCDD_m$$

Base Load Variable

The peak model base load variable (BaseVarm) derived from the sales forecast models is an estimate of the non-weather sensitive load at the time of the monthly system peak demand. The base load variable is defined as:

$$BaseVar_m = ResOtherCP_m \times ComOtherCP_m \mid IndOtherCP_m \mid StLightingCP_m$$

Base load requirements are derived for each revenue class by subtracting out heating and cooling load requirements from total load requirements. Using the SAE modeling framework, class annual base load requirements are then allocated to end-uses at the time of monthly peak demand. For example, the residential water heating coincident peak load estimate is derived as:

$$ResWaterCP_m = ResBaseLoad_m \times \left({ResWaterEI_a}/{ResBaseEI_a} \right) \times ResWaterFrac_m$$

Where

ResWaterEI = Annual water heating intensity (water use per household)
ResBaseEI = Annual base-use intensity (non-weather sensitive use per household)
ResWaterFrac = Monthly fraction of usage on at peak (estimates are based on Itron's hourly end-use load profile database)

End-use load estimates are aggregated by end-use and then revenue class resulting in the base load variable.

Model Results

The model explains monthly peak variation well with an adjusted R^2 of 0.97 and an in-sample MAPE of 2.5%.

CUSTOMER OWNED DISTRIBUTED GENERATION FORECAST

Vectren has been monitoring national and regional distributed generation trends since the 2011 IRP. While a number of technologies continue to influence the electric utility industry, the primary focus is on distributed solar. The present IRP considers the potential for future customer-owned DG growth, specifically in the area of net metered distributed solar photovoltaic (PV) adoption. For modeling purposes, distributed PV is treated as a decrease in demand. A distributed solar forecast was developed using Vectren and Indiana historical net metering information and 3rd party data and assumptions. This forecast is presented below in Table 5-5.

Table 5-5 Distributed Solar Growth Forecast

Year Ending	Historic Peak Planning Capacity (MW)	Distributed Solar Adoption Forecasts: Contribution to Peak Planning Capacity[1] (MW)		
		LOW CASE	HIGH CASE	BASE CASE
2006	0.002			
2007	0.002			
2008	0.003			
2009	0.012			
2010	0.029			
2011	0.051			
2012	0.106			
2013	0.162			
2014		0.2	0.2	0.2
2015		0.3	0.3	0.3
2016		0.4	0.4	0.4
2017		0.5	0.6	0.6
2018		0.7	0.9	0.8
2019		0.9	1.2	1.1
2020		1.3	1.7	1.5
2021		1.7	2.4	2.0
2022		2.3	3.3	2.8
2023		3.0	4.7	3.9
2024		4.1	6.6	5.3
2025		5.5	9.2	7.3
2026		6.2	10.6	8.4
2027		7.0	12.1	9.6
2028		7.8	14.0	10.9
2029		8.9	16.1	12.5
2030		10.0	18.5	14.2
2031		11.3	21.2	16.3
2032		12.7	24.4	18.6
2033		14.3	28.1	21.2
2034		16.2	32.3	24.2

[1] Peak planning capacity is 38% of installed capacity.

Because the IRP is concerned with meeting the annual peak demand, the data presented in Table 5-5 are expressed in terms of megawatts of peak planning capacity, rather than total direct current (DC) gross capacity or total alternating current (AC) inverter capacity. The summer peak typically occurs in late afternoon in mid-to-late summer, whereas maximum solar output is generally at noon in late spring or early summer. Because optimal solar output does not coincide with the summer peak, a factor must be applied to estimate the useful solar capacity from a given PV system at the summer peak. A wide range of peak planning capacity factors have been reported for distributed solar resources.[1] Although MISO has not formally adopted a peak planning capacity factor, PJM, a regional transmission operator, has recommended a factor of 38%.[2] Because of this PJM reference, Vectren has chosen to use this value. There may be further refinements on this going forward as the utility & solar industry further evaluate methodologies for developing this factor, and Vectren may revise this number in future IRPs.

The historical data column reflects the summer peaking capacity of Vectren's reported net metered customer accounts.[3] The High, Low, and Base Case forecasts for the 2014 – 2034 planning horizon are derived from the following information & data sets:

- Vectren historical growth in net metered inverter-rated capacity,
- Indiana historical growth in net metered inverter-rated capacity, and
- Navigant Consulting solar capacity future growth rate assumptions for Indiana.[4]

High Case (applied to the low energy and demand forecast) calculation methodology is as follows:

- Vectren year-end 2013 inverter-rated capacity (426 kW) grows each year in a compounding manner using Navigant's Indiana predicted growth rates as follows:

[1] Sterling, John, and J. McLaren, M. Taylor, K. Cory. Treatment of Solar Resource Generation in Electric Utility Resource Planning. NREL/TP-6A20-60047. October, 2013.
[2] PJM Manual 21: Rules and Procedures for Determination of Generating Capability, revision 11. PJM System Planning Department. March 5, 2014.
[3] Vectren's Customer-Generator Interconnection and Net Metering Report for year ended 12/13/2013.
[4] Navigant Consulting, 5/2/2014.

  - 2014 – 2025: 40% per year
  - 2025 – 2034: 15% per year
- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

Low Case (applied to the high (modeled) energy and demand forecast) calculation methodology is as follows:

- Vectren year-end 2013 inverter-rated capacity (426 kW) grows each year in a compounding manner using slower growth rates as follows:
  - 2014 – 2025: 34.1% per year
  - 2025 – 2034: 12.8% per year
  - These growth rates are a modified version of the High Case's Navigant Indiana rates based on a derived factor.
    - This growth "adjustment" factor is derived by taking historical net metered capacity growth in Vectren territory versus Indiana as a whole.
    - Specifically, this adjustment factor takes the simple average growth rate for Vectren for the years 2010 through 2012 and divides this result by the simple average growth rate for Indiana over the same period.
    - This adjustment factor is 0.852 (or 85.2%). Applying this factor to Navigant's Indiana growth rates yields the 34.1% and 12.8% values given above.
- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

Base Case (applied the base case and high (large load) energy and demand forecasts) calculation methodology is as follows:

- Takes the simple average of the High and Low cases in each year.

- Each year's result is then multiplied by the factor 0.38 to arrive at the peak planning contribution for distributed solar.

The overall approach for the High, Low, and Base cases is a reflection of the difference in the overall net-metered distributed generation customer adoption rates between Vectren and Indiana. It takes a very high level view of how solar adoption may evolve over a relatively long planning horizon. Vectren believes that the long term nature of the IRP process calls for a high level macro approach, and the Navigant assumptions, while very general in nature, represent the results of expert analysis and therefore are an appropriate basis for making this forecast. Navigant did suggest an "adjustment factor" for the Vectren territory because the Vectren service territory is growing at a slower rate than the state of Indiana, resulting in the use of this in the Low case (and indirect use in the Base Case). The High Case utilizes the unadjusted, original Navigant growth rates (where the Vectren growth rate matches the overall state growth rate).

While distributed solar PV, is the most prominent form of distributed generation anticipated in terms of total numbers of customers, it is not the only DG technology to be considered. Cogeneration, or Combined Heat and Power (CHP), is also a key technology category in the context of the IRP. However, because of the case-by-case nature of these potential resources, and the fact that some could be large enough to be modeled as a generation and/or capacity resource, these are covered outside this section on distributed generation.

Additional future technologies in the distributed generation space include:

- Small wind turbines
- Energy storage
- Fuel cells
- Micro turbines
- Other Micro-CHP (e.g. small advanced engine technologies)

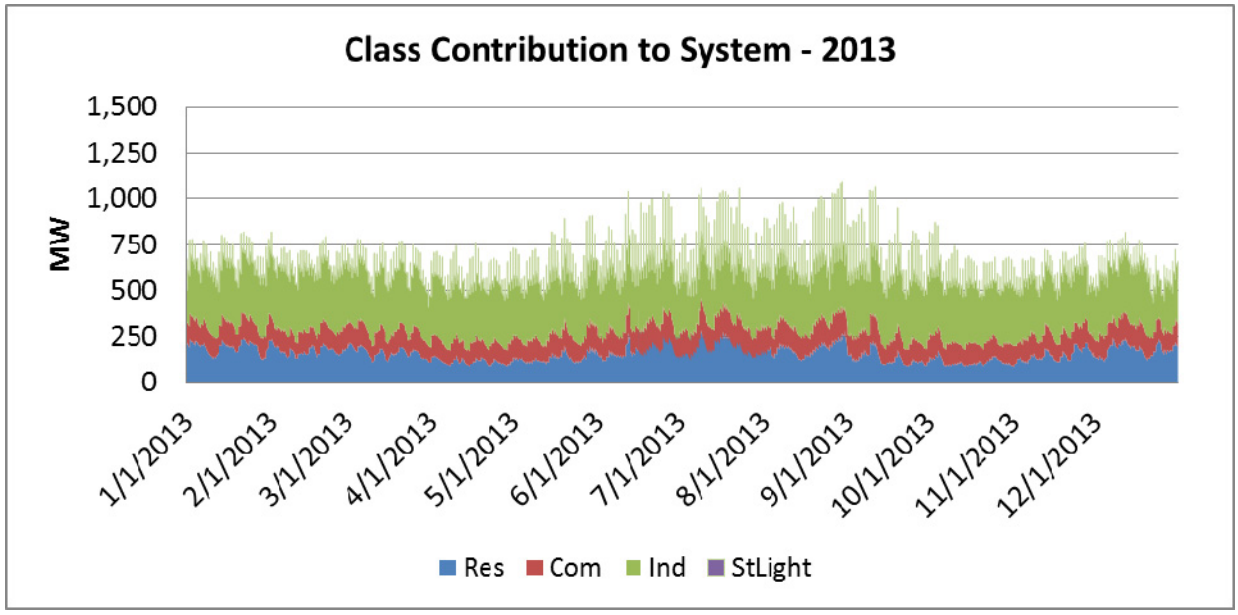
- Micro grids (i.e. customer-sited distribution systems that may include generation and storage technologies)

Each of these technologies will be an important area for the industry to consider in coming years. At this time, none of these are significant enough (or certain enough) to be forecasted as customer-sited DG resources in the present IRP. However, Vectren will continue to monitor and consider how these technologies play into generation planning going forward.

OVERVIEW OF LOAD RESEARCH ACTIVITIES

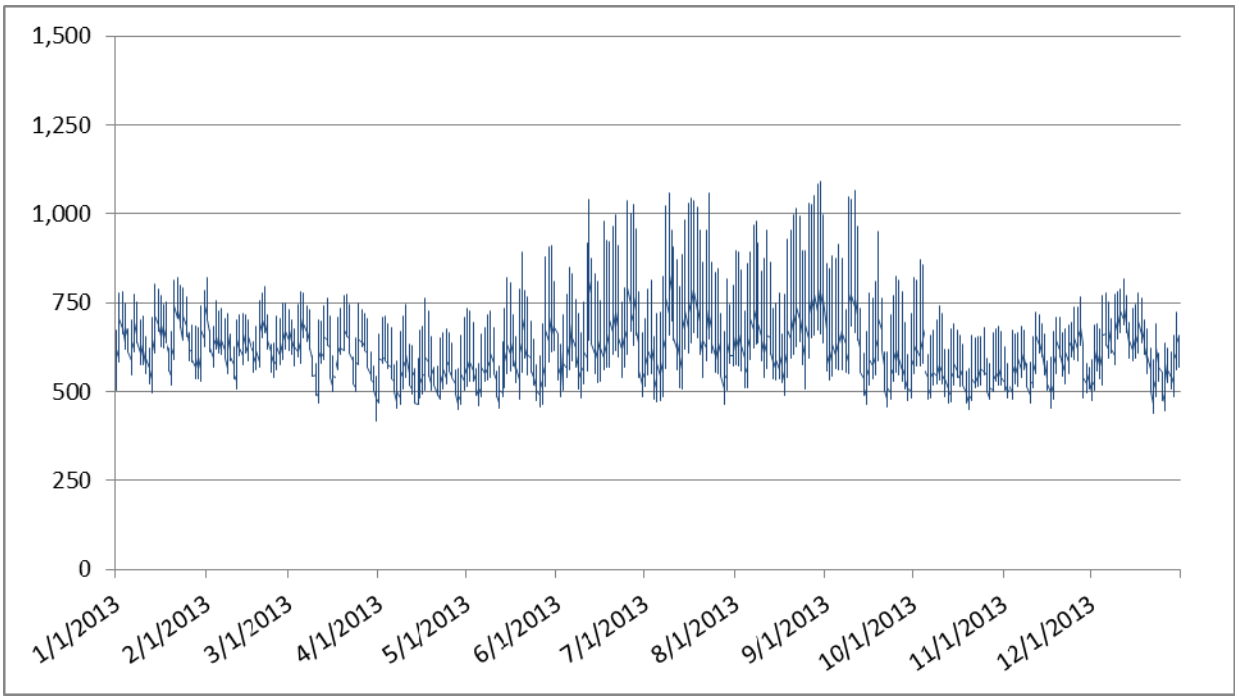
Vectren has interval meters installed on a sample of residential and GS customers. Large customers who have a monthly minimum demand obligation of 300kVA are required to have interval meters installed. Vectren collects and stores this information for analysis as needed. Detailed load shapes are used to better understand customers' usage, primarily for cost of service studies. For this IRP, class load shapes were borrowed from Itron's Indiana library to break down Vectren's hourly load profile by class. The load shapes were applied to historical peak demand. Graph 5-1 shows daily class contribution to peak for 2013.

Graph 5-1 Daily Class Contribution to Peak for 2013 (MW)

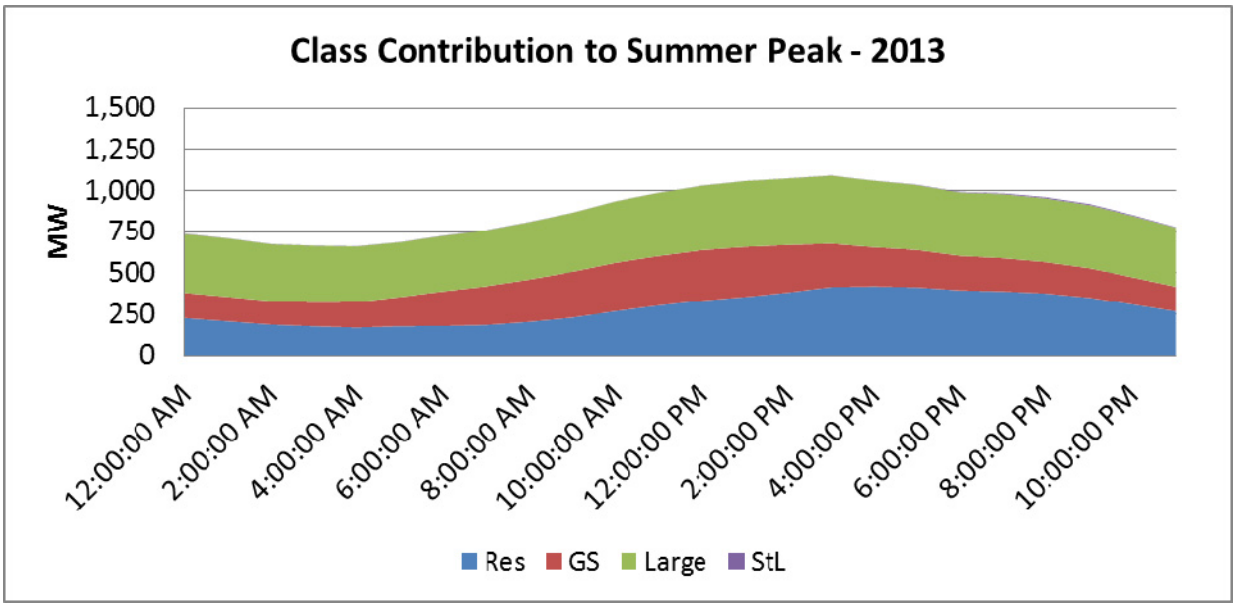


The following graphs (5-2 through 5-4) show the actual system load by day for 2013, the actual summer peak day for 2013 by hour, and the winter peak day for 2013 by hour. Note that these graphs do not include wholesale contract sales. Also additional load shapes are included in the Technical Appendix, section C.

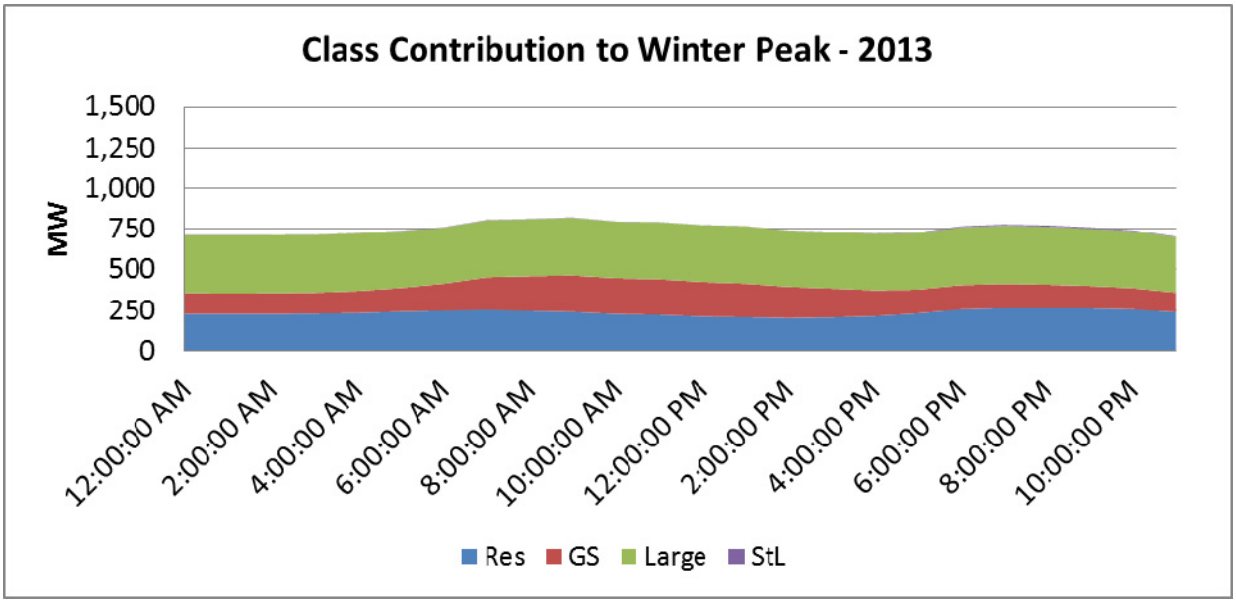
Graph 5-2 Total System Load for 2013 (MW)



Graph 5-3 Summer Peak 2013 (MW)



Graph 5-4 Winter Peak 2013 (MW)



APPLIANCE SATURATION SURVEY AND CONTINUOUS IMPROVEMENT

Vectren typically surveys residential customers every other year. A residential appliance saturation survey was conducted in the summer of 2013. The survey was completed by a representative sample of customers. Results from this survey were used to reflect market shares of actual residential customers. The residential average use model statistics were improved by calibrating East South Central Census regional statistics with the appliance saturation of Vectren's customers. Note that Vectren's service area is technically in the southern most point of the East North Central Census region, bordering the Ease South Central region. Model results were improved by calibrating to the East South Central region.

At this time, Vectren does not conduct routine appliance saturation studies of GS and large customers. These customers are surveyed when needed for special programs. However, Vectren's large and GS marketing representatives maintain close contact with its largest customers. This allows Vectren to stay abreast of pending changes in demand and consumption of this customer group.

Vectren continually works to improve our load forecasting process in a variety of ways. First, Vectren is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Vectren forecasters attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. We compare and contrast our model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

OVERVIEW OF PAST FORECASTS

The following tables outline the performance of Vectren's energy and demand forecasts. Forecasts from previous IRP filings from 2004 through 2013 were compared to actual values in order to evaluate the reliability of Vectren's past energy and demand forecasts. The following tables show the actual and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

Tables 5-6 through 5-10 present comparisons of actual values versus forecasted values from previous IRP filings. The percentage deviation of the actual values from the most recent forecast is shown in the last column of each table. The deviations of the total energy and total peak forecasts are better than for the individual classes, which is to be expected. Note that all of the forecasted values are weather-normalized, but the actual

loads are not. This comparison would show much closer correlation if the actual loads were normalized to match the forecasts. This is particularly true when predicting the peak hour of the year. For example, weather in 2012 was abnormally hot, with multiple 100 degree days in a row, causing the peak demand to be high. 2013 was much milder and, therefore had a lower peak demand. Another factor affecting forecasts is the economic forecast. The recovery from the Great Recession has been much slower than expected. Another source of potential error is the use of the direct load control program, which reduces the peak demand on hot days by cycling off customer appliances to reduce system load. Note that Vectren is not forecasting any firm wholesale contracts after 2014.

Table 5-6 Total Peak Requirements (MW)

		Forecasts						
Year	Actual	2011	2009	2007	2005	2004	2001	Deviation from most recent forecast, %
2004	1,222						1,325	-8.4%
2005	1,316					1,313		0.2%
2006	1,325				1,326			-0.1%
2007	1,341				1,346			-0.4%
2008	1,166			1,184				-1.6%
2009	1,143			1,216				-6.4%
2010	1,275		1,153					9.6%
2011	1,221		1,179					3.4%
2012	1,205	1,168						-3.1%
2013	1,102	1,168						6.0%
Compound Annual Growth Rate, 2004-2013	-1.15%							

Table 5-7 Total Energy Requirements (GWh)

Year	Actual	Forecasts 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	6,303						6,437	-2.1%
2005	6,508					6,624		-1.8%
2006	6,352				6,543			-3.0%
2007	6,527				6,210			4.9%
2008	5,931			6,160*				-3.9%
2009	5,598			6,068				-8.4%
2010	6,221		5,608					9.9%
2011	6,244		5,762					7.7%
2012	5,861	5,896						0.6%
2013	5,822	5,867						0.8%
Compound Annual Growth Rate, 2004-2013	-0.88%							

*Adjusted to include wholesale sales

Table 5-8 Residential Energy Sales (GWh)

Year	Actual	Forecasts 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	1,502						1,553	-3.4%
2005	1,571					1,546		1.6%
2006	1,475				1,584			-7.4%
2007	1,631				1,609			1.3%
2008	1,435			1,581				-10.1%
2009	1,449			1,595				-10.0%
2010	1,598		1,467					8.2%
2011	1,515		1,451					4.2%
2012	1,456	1,501						-3.1%
2013	1,427	1,483						-3.9%
Compound Annual Growth Rate, 2004-2013	-0.57%							

Table 5-9 General Service Energy Sales (GWh)

Year	Actual	Forecasts (GS) 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	1,502						1,408	6.3%
2005	1,556					1,500		3.6%
2006	1,515				1,566			-3.4%
2007	1,412				1,594			-12.9%
2008	1,294			1,380				-6.6%
2009	1,299			1,384				-6.5%
2010	1,361		1,275					6.3%
2011	1,335		1,285					3.8%
2012	1,315	1,387						-5.5%
2013	1,303	1,409						-8.2%
Compound Annual Growth Rate, 2004-2013	-1.57%							

Table 5-10 Large Energy Sales (GWh)

Year	Actual	Forecasts (Large) 2011	2009	2007	2005	2004	2001	Deviation from prior IRP forecast, %
2004	2,346						2,570	-9.5%
2005	2,389					2,619		-9.6%
2006	2,376				2,379			-0.1%
2007	2,538				2,422			4.6%
2008	2,744			2,591				5.6%
2009	2,251			2,598				-15.4%
2010	2,601		2,281					12.3%
2011	2,744		2,445					10.9%
2012	2,714	2,696						0.7%
2013	2,744	2,714						1.1%
Compound Annual Growth Rate, 2004-2013	1.76%							

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CHAPTER 6

ELECTRIC SUPPLY ANALYSIS

INTRODUCTION

The purpose of the electric supply analysis is to determine the best available technologies for meeting the potential future supply-side resource needs of Vectren. A very broad range of supply alternatives were identified in a Technology Assessment described below. These supply alternatives were screened, and a smaller subset of alternatives were chosen for the final planning and integration analysis. Demand side alternatives play a major role in the integrated plan and are discussed in Chapter 8 DSM Resources. The supply-side alternatives which are discussed here fall into two basic categories:

- construction of new generating facilities and
- energy and capacity purchases.

Note that additional DSM energy efficiency programs beyond what was included in the base case energy and demand forecasts were modeled competed with supply-side options to meet future load requirements. This is discussed further in Chapter 8 DSM Resources.

TECHNOLOGY ASSESSMENT

For the 2014 Electric IRP process, Vectren retained the services of Burns & McDonnell, one of the leading engineering design experts in the United States, to assist in performing a Technology Assessment for generation technologies. The Technology Assessment can be found in the Technical Appendix, section B. Below are descriptions of the technologies that were considered from the Technology Assessment.

Natural Gas Technologies

The simple cycle gas turbines (SCGT) utilize natural gas to produce power in a gas turbine generator. The gas turbine cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to their fast load ramp rates and relatively low capital costs.

However, the units have high heat rates compared to other technologies. The different classes of SCGTs are shown below in Table 6-1. Please note that for new natural gas fired units, the capital costs shown in the table above are higher than the overnight costs shown in the Technology Assessment document. A 30% contingency for gas infrastructure siting costs and owner's costs was added for final modeling purposes.

Table 6-1 SGCT Classes

Simple Cycle Gas Turbine				
	LM6000	**LMS100**	**E-Class**	**F-Class**
Base Load Net Output (MW)	49.1	106.4	87.5	212.8
Base Load Net Heat Rate (HHV Btu/kWh)	9,570	8,860	11,480	9,940
Base Project Costs (2014$/kW)	$2,047	$1,440	$1,704	$1,228
Fixed O & M Costs (2014$/kW-yr.)	$23.98	$11.18	$16.56	$7.42

The combined cycle gas turbines (CCGT) utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive a steam turbine and generator to produce electric power. The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and low emissions. For this assessment, a 1x1, 2x1, and 3x1 power block, as shown in Table 6-2, was evaluated with General Electric (GE) 7F-5 turbines as representative CCGT technology. A 1x1 means one gas or steam turbine is coupled with one HRSG. A 2x1 means two gas or steam turbines are coupled with one HRSG. A 3x1 follows the same pattern, meaning that there are three gas or steam turbines coupled with one HRSG.

Table 6-2 CCGT Classes

Combined Cycle Gas Turbine			
	1x1 F-Class Unfired	**2x1 F-Class Unfired**	**3x1 F-Class Unfired**
Base Load Net Output (MW)	405.5	815.5	1227.1
Base Load Net Heat Rate (HHV Btu/kWh)	6,610	6,530	6,500
Base Project Costs (2014$/kW)	$1,400	$1,083	$925
Fixed O & M Costs (2014$/kW-yr)	$13.51	$7.62	$5.79

The reciprocating engine is the last of the natural gas alternative technologies evaluated. The reciprocating, or piston, engine operates on the conversion of pressure into rotational energy that will fire on natural gas. Fuel and air are injected into a combustion chamber prior to its compression by the piston assembly of the engine. A spark ignites the compressed fuel and air mixture causing a rapid pressure increase that drives the piston downward. The piston is connected to an offset crankshaft, thereby converting the linear motion of the piston into rotational motion that is used to turn a generator for power production. The reciprocating engine is shown in Table 6-3.

Table 6-3 Reciprocating Engine

Reciprocating Engine	
Base Load Net Output (MW)	100.2
Base Load Net Heat Rate (HHV Btu/kWh)	8,470
Base Project Costs (2014$/kW)	$1,677
Fixed O & M Costs (2014$/kW-yr)	$11.79

Coal Technologies

Pulverized coal steam generators are characterized by the fine processing of the coal for combustion in a suspended fireball. Coal is supplied to the boiler from bunkers that direct coal into pulverizers, which crush and grind the coal into fine particles. The primary air system transfers the pulverized coal from the pulverizers to the steam generator's low NO_x burners for combustion. The steam generator produces high-pressure steam for throttle steam to the steam turbine generator. The steam expansion provides the energy required by the steam turbine generator to produce electricity.

Another type of coal technology that was evaluated was the Integrated Gasification Combined Cycle (IGCC) technology. IGCC technology produces a low calorific value syngas from coal or solid waste that can be fired in a combined cycle power plant. The gasification process itself is a proven technology used extensively for chemical production of products such as ammonia for fertilizer.

See Table 6-4 for further details on the coal technologies evaluated.

Table 6-4 Coal Technologies

Coal			
	Supercritical Pulverized Coal 1	**Supercritical Pulverized Coal 2**	**2x1 Integrated Gasification CC**
Base Load Net Output (MW)	425	637.5	482
Base Load Net Heat Rate (HHV Btu/kWh)	10,500	10,200	11,470
Base Project Costs (2014$/kW)	$5,568	$5,080	$10,698
Fixed O & M Costs (2014$/kW-yr)	$32.41	$21.54	$36.88

Waste to Energy Technologies

Stoker boiler technology is the most commonly used waste to energy (WTE) or biomass technology. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator for the production of electricity. The two fuel types evaluated in the IRP was wood and landfill gas which are represented in Table 6-5.

Table 6-5 Waste to Energy Technologies

Biomass		
	Wood Stoker Fired	**Landfill Gas IC Engine**
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,500	10,500
Base Project Costs (2014$/kW)	$4,542	$3,261
Fixed O & M Costs (2014$/kW-yr)	$94.49	$182.88

Renewable Technologies

Four renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, solar thermal, and hydroelectric. Most of the data evaluated was taken from the Technology Assessment, but some data used was from updated studies or real-life examples which will be further discussed below.

Wind turbines convert the kinetic energy of wind into mechanical energy, and are typically used to pump water or generate electrical energy that is supplied to the grid. Subsystems for either configuration typically include a blade or rotor to convert the energy in the wind to rotational shaft energy, a drive train, usually including a gearbox and a generator, a tower that supports the rotor and drive train, and other equipment,

including controls, electrical cables, ground support equipment and interconnection equipment. All the data evaluated for wind energy came from the Technology Assessment.

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into diverse mix of technological designs. Solar conversion technology is generally grouped into Solar Photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell, and Solar Thermal technology, which converts the radiant heat of the solar energy to electricity through an intermediary fluid.

Photovoltaic (PV) cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other.

Solar Thermal technology transfers solar energy to an intermediary liquid (typically mineral oil or molten sodium and potassium nitrate salts) in the form of heat, which is then used to boil water and produce steam. That steam is sent to a Steam Turbine Generator (STG) for the production of electricity. The life expectancy of a solar thermal power plant is similar to that of any fossil fueled thermal plant as long as preventative and routing maintenance programs are undertaken.

Vectren recognized that utility scale solar costs are expected to decline over the next few years and decided to have Burns & McDonnell revisit the solar portion of this Technology Assessment, which had a static cost for solar. Burns & McDonnell's

Phoenix office, which has extensive knowledge of the solar industry, developed an asymptotic curve, beginning at $1,880 per KWac in 2014, and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon. The declining cost curve was used for Vectren's IRP modeling. The costs are represented in Table 6-6.

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. Specially designed low-head hydro turbines are often current driven, and therefore operate at low speeds of 100 to 500 rpm in various configurations and orientations. Since they do not require a large head loss, low-head hydroelectric facilities can be incorporated in a variety of different applications, including rivers, canals, aqueducts, pipelines, and irrigation ditches. This allows the technology to be implemented much more easily than conventional hydropower, with a much smaller impact to wildlife and environmental surroundings. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions such as dense vegetation or algae growth, sediment levels, and drought. Additionally, low-head hydropower is relatively new and undeveloped, resulting in a high capital cost for the relatively small generation output.

Vectren utilized a previously performed study that included dams in and around Vectren's electric service territory to help provide guidance for this IRP. The study was titled *Hydropower Resource Assessment at Non-Powered USACE Sites* and was prepared by the Hydropower Analysis Center for U. S. Army Corps of Engineers. The study was finalized in July 2013.[1] Since there were no costs in the study, Vectren used a real-life example from a hydroelectric construction project in the area to gather the project costs. This data is represented in table 6-6.

[1] Vectren referenced page 28 of this analysis.

Table 6-6 Renewable Technologies

Renewable				
	Wind	**Solar PV**	**Solar Thermal**	**Hydroelectric**
Base Load Net Output (MW)	50	50	50	50
Capacity Factor (energy annual output)	Intermittent (27%)	Intermittent (19%)	Intermittent (19%)	44%
Base Project Costs (2014$/kW)	$2,296	$1,880[1]	$5,740	$4,966
Fixed O & M Costs (2014$/kW-yr)	$25.40	$17.27	$35.56	$76.20

Energy Storage Technologies

Two energy storage technologies were evaluated in the IRP. The technologies were batteries and Compressed Air Energy Storage (CAES). These are shown in Table 6-7.

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity.

CAES offers a way of storing off-peak generation that can be dispatched during peak demand hours. To utilize CAES, the project needs a suitable storage site, either above ground or below ground, and availability of transmission and fuel source. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander.

[1] $1,880 per KWac in 2014, and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon.

Table 6-7 Energy Storage Technologies

Energy Storage		
	Advanced Battery Energy Storage	**Compressed Air Energy Storage**
Base Load Net Output (MW)	10	135
Base Project Costs (2014$/kW)	$4,135	$1,240
Fixed O & M Costs (2014$/kW-yr)	$60.96	$7.11

Nuclear Technologies

Manufacturers have begun designing Small Modular Reactors (SMRs) to create a smaller scale, completely modular nuclear reactor. These modular reactors are on the order of 30 feet in diameter and 300 feet high. The conceptual technologies are similar to Advanced Pressurized Water Reactors (APWR), and the entire process and steam generation is contained in one modular vessel. The steam generated in this vessel is then tied to a steam turbine for electric generation. The benefit of these SMRs is two-fold; the smaller unit size will allow more resource generation flexibility and the modular design will reduce overall project costs while providing increased benefits in the areas of safety and concern, waste management, and the utilization of resources. The 225 MW SMR facility is shown in Table 6-8.

Table 6-8 Nuclear SMR Technology

Nuclear	
	Small Modular Reactor
Base Load Net Output (MW)	225
Base Load Net Heat Rate (HHV Btu/kWh)	10,300
Base Project Costs (2014$/kW)	$5,415
Fixed O & M Costs (2014$/kW-yr)	$90.42

NEW CONSTRUCTION ALTERNATIVE SCREENING

The first step in the analysis of new construction alternatives was to survey the available list of technologies and to perform a preliminary screening of each of the options, eliminating those options that were determined to be unfeasible or marginal. The power supply alternatives Vectren considered include intermediate and peaking options, as well as renewable generation, energy storage, distributed generation, and demand side management. These power supply alternatives were screened using a bus bar cost analysis. This was done in order to reduce the number of alternatives that were evaluated to a manageable level within Strategist, the planning model.

The screening analysis was performed by developing and comparing levelized cost of each resource over a 20 year period. This simple approach is used to identify and limit the number of higher-cost generation alternatives. For screening purposes, estimated costs included fuel, operation & maintenance, and capital costs. Resources were then compared across various capacity factors in order to compare resource costs across all dispatch levels. Intermittent resources were compared at their respective output levels. Demand side management (DSM) and distributed generation (DG) were not considered in the bus bar analysis, but were considered alternatives within the IRP. See Chapter 5 Sales and Demand Forecast and Chapter 8 DSM Resources for more details.

The set of new construction alternatives that was selected for further assessment as a result of the screening process are presented in Table 6-9. The capital cost and O&M characteristics of these selected alternatives were assessed and developed in detail.

Table 6-9 New Construction Alternatives

Resource[1]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
7FA CCGT 1x1	405.5	Natural Gas	Accept	Cost Effective Option
7FA CCGT 2x1	815.5	Natural Gas	Reject	Exceeds capacity needs. If pursuit of a Combined Cycle was needed, would consider coordinating with another utility in order to reduce costs.
7FA CCGT 3x1	1227.1	Natural Gas	Reject	Exceeds capacity needs. If pursuit of a Combined Cycle was needed, would consider coordinating with another utility in order to reduce costs.
1xLM6000	49.1	Natural Gas	Accept	Cost Effective for 50 MW or less
1xLMS100	106.4	Natural Gas	Reject	Not Cost Effective compared to alternatives
1xE-Class SCGT	87.5	Natural Gas	Reject	Not Cost Effective compared to alternatives
1xF-Class SCGT	212.8	Natural Gas	Accept	Cost Effective for low capacity factors
100 MW Recips	100.2	Natural Gas	Accept	Cost Effective for 100 MW or less
500 MW Supercritical Pulverized Coal	425	Coal	Reject	Not Cost Effective compared to alternatives
750 MW Supercritical Pulverized Coal	637.5	Coal	Reject	Not Cost Effective compared to alternatives
2x1 Integrated Gasification Combined Cycle	482	Coal	Reject	Not Cost Effective compared to alternatives
Wood Stoker Fired	50	Biomass	Reject	Not Cost Effective compared to alternatives
Landfill Gas IC Engine	5	Biomass	Reject	Not Cost Effective compared to alternatives
10 MW Adv. Battery Energy Storage	10	Energy Storage	Reject	Not Cost Effective compared to alternatives
135 MW Compressed Air Energy Storage	135	Energy Storage	Reject	Not Cost Effective compared to alternatives
50 MW Wind Energy Conversion	50	Renewables	Accept	Cost Effective Renewable Source
50 MW Solar PV	50	Renewables	Accept	Cost Effective Renewable Source
50 MW Solar Thermal	50	Renewables	Reject	Not Cost Effective compared to PV
50 MW Low-head Hydro	50	Renewables	Reject	Not Cost Effective compared to alternatives
Small Modular Nuclear	225	Uranium	Reject	Not Cost Effective compared to alternatives

[1] Resource options could be structured as a PPA or be utility owned

Gas-Fueled Technologies

Two major types of gas-fired power generation technology, representing six alternatives, were selected for the detailed assessment. These were either simple cycle or combined cycle technology.

- Simple cycle gas turbine (SCGT) technology was evaluated for four levels of generating capability.
- Combined cycle gas turbine (CCGT) technology was evaluated for two levels of generating capabilities.

Simple cycle alternatives were included in the final integration analysis. With respect to the combined cycle alternatives, this assumption was made on the basis of capturing economies of scale and high efficiencies while satisfying the reserve margin and capital investment constraints.

Renewable Technologies

Two renewable resources were included in the final integration analysis. The renewable resources were modeled in 50 MW blocks to be evaluated against the other new construction alternative options. The 50 MW blocks are an installed capacity (ICAP) or generation nameplate designation. The renewable technologies that were selected by the bus bar cost analysis included wind and solar photovoltaic (PV). These renewable resources are intermittent resources, meaning that they are not continuously available due to some factor outside direct control. Given that this analysis is based on unforced capacity (UCAP), the resources are converted from the installed capacity to the unforced capacity based on the percentage of the designated resource. For wind, 9.125% was used to calculate the amount of UCAP available. This effectively makes every 50 MW block of wind worth 4.56 MW towards meeting the UCAP requirement. For solar PV, 38% was used to calculate the amount of UCAP available. This makes every 50 MW block of solar PV worth 19 MW towards meeting the UCAP requirement. See Chapter 5 Sales and Demand Forecast for more details.

PURCHASED POWER ALTERNATIVES

Another set of options available for assisting in meeting future supply-side resource requirements is purchased power from the wholesale electric market for both capacity and/or energy needs. Vectren is a participant in the wholesale electric power market and is a member of the ReliabilityFirst (RF), a regional reliability organization operating within the framework of the North American Electric Reliability Council (NERC). Vectren is also a member of MISO, the independent transmission system operator that serves much of the Midwest and Canada.

Estimating the future market price for electric energy available for purchase is difficult. In general, forward market information for "standard" products is available from brokers, counterparties, and published price indices. However, the liquidity and price transparency of the forward market is inversely proportional to the proximity of the delivery date of the product. The forward market becomes much less liquid (less trade volume) as the delivery date of the product moves further out into the future. Price discovery is more difficult as the more forward products are traded less and therefore less transparent.

Capacity prices within MISO are on an upward trend that may last for several years. Vectren does not foresee a near term need for capacity. In the long run, regional reserve margins will approach equilibrium due to a combination of load growth and generation retirements. Capacity prices may converge with replacement build prices as surplus legacy capacity diminishes through unit retirements and market growth. If at some future point in time Vectren foresees a projected need for capacity, purchased power options will be fully and explicitly considered at that time.

CUSTOMER SELF- GENERATION

Customer self-generation or behind the meter generation is likely to increase in the future. As discussed in in Chapter 5 Sales and Demand Forecast, a future trend of distributed rooftop solar has been projected and included in all scenarios. Somewhat more difficult to predict is the industrial adoption of behind the meter generation. One such facility is planned by a large industrial customer with a proposed implementation in 2017. As these types of projects become known they are incorporated into Vectren's forecasts. They are not however a typical trend, and therefore, are not projected beyond the known projects.

Some large electric customers may be candidates for cogeneration opportunities. Vectren's marketing department is in periodic discussions with customers most likely to participate in such a project. Should such a scenario develop, Vectren would work with that customer to see if they would benefit Vectren's customers to participate in such a project by possibly increasing the output of the cogeneration plant and thus supplying the Vectren system with the excess. Such a project can only be evaluated on a case by case basis.

RENEWABLE TECHNOLOGIES

Wind

As will be discussed further in Chapter 7 Renewables and Clean Energy, Vectren has two separate long-term purchase power agreements for a total of 80 MW of wind name plate capacity. These agreements were included in all integration analysis cases for the entire 20 year study period.

Other

Landfill gas projects and biomass are viable renewable sources of energy. However, due to their typically small relative size and unique site situations required for development, they weren't considered explicitly in the Technology Assessment or included in the integration analysis of this IRP. Vectren believes these technologies may be considered for viable projects in the future, primarily in the context of distributed generation as discussed in the following section, and that such projects will be duly evaluated as they develop.

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CHAPTER 7

RENEWABLES

and

CLEAN ENERGY

CURRENT PROJECTS

Vectren currently receives renewable energy from three projects: two purchase power contracts from Indiana wind projects and one landfill methane gas project.

Benton County Wind Farm

The Benton County Wind Farm, located in Benton County, Indiana, began providing electricity to Vectren in May 2007 under a 20 year purchase power agreement. The nominal nameplate rating for this contract is 30 MW, and the expected annual energy to Vectren from this project is 76,500 MWh.

Fowler Ridge II Wind Farm

Vectren began receiving energy from the Fowler Ridge II wind farm, also located in Benton County, Indiana in December of 2009 under a 20 year purchase power agreement. The nominal nameplate rating for this contract is 50 MW, and the expected annual energy to Vectren from this project is 130,500 MWh.

Blackfoot Landfill Gas Project

Vectren owns the Blackfoot Landfill Clean Energy Project located in Pike County, Indiana. Vectren officially took over ownership of this project on June 22, 2009. This facility consists of 2 internal combustion engine-generator sets that burn methane gas collected from the adjacent Blackfoot Landfill. Total nameplate capacity is 3.2 MW gross combined for the two machines. Vectren projects to produce approximately 15,000 MWh per year from this facility. Pending future expansion of the Blackfoot landfill and corresponding development of a viable gas field, Vectren may consider adding an additional generator set to this facility at some point in the future.

RENEWABLE ENERGY CREDITS

In addition to participation in actual renewable energy projects, both through ownership and purchase power agreements, Vectren will also consider purchasing renewable energy credits (RECs) to meet future renewable mandates. Vectren will monitor the

market development for RECs over the next several years to determine the soundness of such a strategy.

ADDITIONAL RENEWABLE AND CLEAN ENERGY CONSIDERATIONS

Vectren modeled generation characteristics for output at time of peak load and capacity factor based on its geographic footprint. Additional wind generation with characteristics similar to Vectren's existing wind PPA's was also considered. Demand side management programs were considered as clean energy resource options and competed directly with other supply side options in the model.

Table 7-1 Clean Energy Projections

		Clean Energy Source					
	Retail Sales before conservation programs	Wind Generation	Landfill Gas Generation	Conservation Programs	Year-Over-Year Conservation Increase	Customer-Owned DG	Vectren Clean Energy
Year	GWh	GWh	GWh	GWh	GWh	GWh	% of sales
2014	5,832	207.0	15	157		1	7%
2015	5,991	207.0	15	182	26	1	7%
2016	6,040	207.0	15	208	26	2	8%
2017	5,645	207.0	15	233	25	3	9%
2018	5,661	207.0	15	258	25	3	9%
2019	5,680	207.0	15	283	25	5	9%
2020	5,699	207.0	15	296	13	7	9%
2021	5,710	207.0	15	309	13	9	10%
2022	5,729	207.0	15	321	13	12	10%
2023	5,746	207.0	15	334	13	17	10%
2024	5,769	207.0	15	347	13	23	10%
2025	5,782	207.0	15	360	13	32	11%
2026	5,801	207.0	15	373	13	37	11%
2027	5,825	207.0	15	386	13	42	11%
2028	5,860	207.0	15	399	13	48	12%
2029	5,884	207.0	15	412	13	55	12%
2030	5,913	207.0	15	426	13	62	12%
2031	5,942	207.0	15	439	13	71	13%
2032	5,985	207.0	15	453	14	81	13%
2033	6,018	207.0	15	466	14	93	13%
2034	6,060	207.0	15	480	14	106	14%

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CHAPTER 8

DSM RESOURCES

INTRODUCTION

The demand-side resource assessment process is based on a sequential series of steps designed to accurately reflect Vectren's markets and identify the options which are most reasonable, relevant, and cost-effective. It is also designed to incorporate the guidelines from the IURC. This chapter presents a discussion of the planning and screening process, identification of the program concepts, and a listing of the demand-side management (DSM) options passed for integration. Additionally, IRP DSM modeling is discussed.

HISTORICAL PERFORMANCE

Since 1992, Vectren has utilized DSM as a means of reducing customer load and thereby providing reliable electric service to its customers. Historically, DSM programs provided both peak demand and energy reductions. DSM programs were approved by the Commission and implemented pursuant to IURC orders. These programs were implemented, modified, and discontinued when necessary based on program evaluations. Vectren has managed the programs in an efficient and cost effective manner, and the load reductions and energy savings from the programs have been significant. Between 2010 and 2013, Vectren DSM programs reduced demand by over 25,000 kW and provided annual incremental energy savings of over 130,000,000 kWh. It is anticipated that in 2014, Vectren will save an incremental 58,000,000 kWh of gross energy savings and approximately 15,000 kW in demand savings.

Vectren also operates a Direct Load Control (DLC) program that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours. This demand response program commenced in 1992 and over 27,000 customers are enrolled with approximately 17 MW of peak reduction capacity.

EXISTING DSM RESOURCES and PROGRAMS

Tariff Based Resources

Vectren has offered tariff based DSM resource options to customers for a number of years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all of Vectren's DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938, and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is available to rate schedule RS, B, SGS, DGS, MLA, OSS, LP, and HLF customers.

Interruptible Rates

In addition to the DSM programs described in this chapter, Vectren has offered interruptible rate programs for commercial and industrial customers. Vectren currently has approximately 47 MW of interruptible load under contract, not including the DLC Program. In addition to the riders listed below, Vectren has one customer on a special contract interruptible rate (as approved by the IURC), that makes up approximately 20 MW of the total 47 MW of interruptible load.

<u>Rider IP – 2 Interruptible Power Service</u>

This rider is available to rate schedule DGS, OSS, LP, and HLF customers with an interruptible demand of at least 200 kW who were taking service under this rider during September 1997. This rider is closed to new participants. This rider currently has two customers that represent approximately 6 MW of the total interruptible load.

Rider IC Interruptible Contract Rider

This rider is available to any rate schedule LP or HLF customer electric who can provide for not less than 1,000 kVa of interruptible demand during peak periods. This rider currently has two customers that represent approximately 21MW of the total interruptible load.

Rider IO Interruptible Option Rider

This rider is available to any rate schedule DGS, MLA, OSS, LP, or HLF customer who will interrupt a portion of their normal electrical load during periods of request from Vectren. A Customer's estimated load interruption capability must exceed 250 kW to be eligible. This rider is not applicable to service that is otherwise interruptible or subject to displacement under rate schedules or riders of Vectren. Customers currently taking service under Vectren's rider IP – 2, which is closed to new business, may apply for service under this rider, if eligible, for the balance or renewal of the existing contracts.

Direct Load Control (DLC)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating and pool pumps (on existing units only) through radio controlled load management receivers (LMR). The DLC program was implemented in April 1992 by Vectren, with the objective of reducing summer peak demand by direct, temporary cycling of participating central air conditioners and heat pumps and by shedding connected water heating and pool pump loads. Participating customers receive credits on their bills during the months of June through September based on the number and type of equipment participating in the program. The DLC program was identified, in 2007, as part of Vectren's DSM Market Assessment study, prepared by Forefront Economics Inc. and H. Gil Peach & Associates LLC, as "…of high quality and notable for its participation and program longevity." Vectren's customers have achieved significant benefits from the existing DLC program.

The program consists of the remote dispatch and control of a DLC switch installed on participating customers' central cooling units (central air conditioners and heat pumps), as well as electric water heating units where a DLC switch is also installed on the central cooling unit. Vectren can initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren can initiate a load control event for several reasons, including: to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from the Midcontinent Independent Transmission System Operator, Inc. (MISO), the regional electricity transmission grid authority. The control of central cooling units is typically a 50% cycling strategy and involves cycling the compressor off for 15 minutes out of every half hour during the cycling period. The direct load control of water heating equipment utilizes a shedding strategy. This involves shutting off these units for the duration of the cycling period. Cycling periods can range between two and six hours in duration.

Vectren manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

The DLC system has the capability to obtain approximately 17 MW of peak reduction capacity from the DLC system. Over time, the operability of the DLC switches can decline for a variety of reasons, including mechanical failure, contractor or customer disconnection, and lack of re-installation when customer equipment is replaced. In order to continue to obtain the peak demand response benefits from the DLC system, Vectren requested and received Commission approval of a multi-year DLC Inspection & Maintenance Program in Cause No. 43839. This inspection process began in 2011 with approximately 25% of the DLC switches inspected annually and this process will be

completed early in 2015. Vectren has proposed in Cause No. 43405 DSMA 12 to continue ongoing maintenance of DLC switches on a five (5) year cycle with approximately 20% inspected annually. The work will continue to be conducted by trained vendors for both the inspection and replacement components of the program. By investing in the inspection and maintenance of the DLC system, Vectren can continue its ability to rely on this demand reduction resource as part of its resource planning.

As of May 2014, Vectren's DLC Program had approximately 27,040 residential customers and 530 commercial customers with a combined total of over 36,000 switches. Note that a customer may have more than one switch at a residence or business.

Cause No. 43839 – Rate Design

In Cause No. 43839, approved by the IURC on May 3, 2011, specific structural rate modifications were proposed by Vectren to better align Vectren's rate design to encourage conservation. These structural changes include:

- For all rate schedules, Vectren separated its variable costs from its fixed costs. These changes are intended, among other things, to provide more clarity and transparency in the rate schedules as to the variable costs that Vectren customers can avoid as customers reduce usage.
- Combined the customers under Rate A (the "Standard" customers) and Rate EH (the "Transitional" customers) into a single rate schedule, called Rate RS - Residential Service. The results of these changes resulted in the elimination of the Rate A declining block rate design in favor of a single block rate design for the Rate RS - Standard customer group versus the previous declining block rates. The transition from a declining block rate design to a flat block rate design has been recognized as a method to encourage energy conservation.
- The availability of Rate RS-Transitional was closed to new customers on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition

plan to gradually move the existing Rate RS-Transitional customers to RS-Standard was to be filed for the Commission's consideration within two years of Vectren's most recent electric rate case on May 3, 2011. Vectren filed with the Commission a report on the Transition Plan on April 23, 2013 and recommended that any transition plan be considered in the next base rate case. The Commission has not yet ruled on this matter.

- The availability of the commercial Rate OSS (Off Season Service) was also closed to new customers on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition plan to gradually move the existing Rate OSS customers to a comparable Rate DGS was to be filed for the Commission's consideration within two years of Vectren's most recent electric rate case on May 3, 2011. Vectren filed with the Commission a report on the Transition Plan on April 23, 2013 and recommended that any transition plan be considered in the next base rate case. The Commission has not yet ruled on this matter.

In Vectren's last electric base rate case, the Company proposed a decoupling mechanism that would break the link between recovery of fixed costs and energy sales in order to eliminate the financial harm to the Company caused when customers reduce their electric usage, thereby supporting the Company's ability to aggressively promote energy conservation. The Commission ultimately denied this request in their April 27, 2011 Order.

The rate structure listed above is reflected in the long term sales and demand forecast.

MISO DR Program

Vectren rider DR provides qualifying customers the optional opportunity to reduce their electric costs through customer provision of a load reduction during MISO high price periods and declared emergency events. Rider DR currently offers two programs, emergency demand response ("EDR") and demand response resource Type 1 ("DRR-1") energy programs.

Rider DR is applicable to any customer served under rates DGS or OSS with prior year maximum demand greater than 70 kW, MLA, LP, or HLF. A customer may participate in the rider DR only with kVa or kW curtailment load not under obligation pursuant to rider IC or IO or special contract. Customers must offer Vectren a minimum of one (1) MW of load reduction, or the greater minimum load reduction requirement that may be specified by the applicable MISO BPM for the type of resource offered by customer. A customer may participate in an aggregation as described in the Rider DR in order to meet the minimum requirement.

Vectren currently does not have any customers participating in rider DR.

Net Metering – Rider NM

Rider NM allows certain customers to install renewable generation facilities and return any energy not used by the customer from such facilities to the grid. On July 13, 2011 the Commission published an amended net metering rule, which included additional modifications to the rules, including eligibility to all customer classes, increase to the size of net metering facilities (1 MW) and an increase in the amount of net metering allowed (1% of most recent summer peak load or approximately 11.5 MW). The new rules also required that at least forty percent (40%) of the amount of net metering allowed would be reserved solely for participation by residential customers.

Vectren has worked with customers over the past several years to facilitate the implementation of net metering installations. As of July 1st, 2014, Vectren had 69 net metering customers with a total nameplate capacity of 474 kW.

Smart Grid Resources

Smart Grid technology has the potential to enable higher levels of reliability, energy efficiency and demand response, as well as improved evaluation, measurement, and verification of energy efficiency and demand response efforts. Reliability can be improved through distribution automation (DA) enhancements. These enhancements

can provide operators with real-time information that allows them to make operational decisions more quickly to restore customers following an outage or possibly avoiding the outage completely. Additionally the enhancements can provide automation that can identify fault location, isolate and restore the customers quickly without operator intervention. The advanced metering infrastructure (AMI) portion of a Smart Grid project, as well as new dynamic pricing offerings, enable those customers who decide to actively manage their energy consumption to have access to significantly more information via enhanced communication. This provides those customers a better understanding and more control of their energy consumption decisions and the resulting energy bills. These improvements can provide benefits toward carbon foot print reduction as a result of the overall lowered energy consumption. The potential DSM benefits related to Smart Grid include:

- Peak reductions resulting from enabling Vectren customers to actively participate in demand response programs via dynamic pricing programs,
- Enhanced load and usage data to the customer to foster increased customer conservation, and
- Conservation voltage and line loss reductions due to the improved operating efficiency of the system.

In 2009, as part of the funding available from the United States Department of Energy (DOE) pursuant to American Recovery and Reinvestment Act (ARRA), Vectren conducted a business case analysis of the broad benefits of a Smart Grid implementation. According to the October 27, 2009 DOE announcement, Vectren did not receive a grant award for the Smart Grid project. Vectren re-evaluated the business case and determined that it would not be prudent to proceed with a broad Smart Grid project at this time due to net costs to customers. As part of this initiative Vectren completed the development of an initial Smart Grid strategy where it identified the need to invest in some foundational communication and information gathering technology in order to support future demand response and load management technology. The initial focus of the strategy is to build out a communication network that will support current

and future Smart Grid technology, such as distribution Supervisory Control and Data Acquisition (SCADA), AMI, conservation voltage reduction (CVR), and system automation. Vectren has implemented a fiber optic communication path across its transmission network, connecting at both primary generating stations. Additional fiber installations are in progress across the transmission grid. The build out of the communication system has allowed Vectren to install and monitor additional SCADA points from its distribution substations. These SCADA installations are fundamental to the potential implementation of future conservation and voltage management programs, such as CVR, on the distribution network. Vectren will continue to monitor and evaluate Smart Grid technologies and customer acceptance of Smart Grid enabled energy efficiency and demand response.

Vectren recognizes the potential benefits Smart Grid technology programs offer. While a comprehensive Smart Grid deployment is likely several years in the future, the goal of any Vectren Smart Grid project will be to improve reliability, reduce outage restoration times, and increase energy conservation capabilities. The foundational investments currently being made and those planned over the next few years will enhance Vectren's ability to achieve these benefits.

The potential impacts of a robust Smart Grid implementation that would include dynamic pricing, improved information or conservation voltage reduction have not been explicitly quantified in this IRP because no specific project of this magnitude has been proposed by Vectren. We continue to monitor these technologies for potential future implementation as they become cost effective for our customers.

FEDERAL AND STATE ENERGY EFFICIENCY DEVELOPMENTS

Federal – Codes, Standards and Legislation

Energy efficiency policies are gaining momentum at both the state and Federal level. Although there are numerous activities going on at the state and Federal level the

following are components of significant legislation that are approaching implementation, as well as new codes, standards and legislation being considered that will likely have an impact on energy efficiency in the planning horizon.

- On June 2, 2014, the EPA released its Clean Power Plan proposal that, if implemented, will for the first time regulate carbon dioxide (CO_2) emissions from existing power plants at the U.S. federal level. The rule is designed to cut carbon pollution from power plants nationwide by 30 percent from 2005 levels. State compliance includes several paths, one of which is end use energy efficiency. While dependent on the actual state implementation plan, the proposed plan would require reductions of 0.57% starting in 2017 and ramping up to 1.5% annually from 2022-2036. By 2030, the EPA is looking for usage reductions in Indiana of 11.6% in cumulative savings and that number increases to 12.9% in cumulative savings by 2036. As this rule is developed and finalized, it is likely to have potential significant impacts on energy efficiency planning.
- The U.S. Department of Energy's Appliances and Equipment Standards Program develops test procedures and minimum efficiency standards for residential appliances and commercial equipment. On June 27, 2011, amended standards were issued for residential central air conditioners and heat pumps. Central air conditioners and central air conditioning heat pumps manufactured on or after January 1, 2015 will have minimum requirements for Seasonal Energy Efficiency Ratios (SEER) and Heating Seasonal Performance Factors (HSPF).

State – Codes, Standards and Legislation

Since 2009, Indiana has taken several significant steps to enhance energy efficiency policy in the state.

- In 2009, the IURC released the Phase II Generic DSM order. The order established statewide electric savings goals for utilities starting in 2010 at

0.3% of average sales and ramping to 2% per year by 2019, The Phase II order also defined a list of five (5) Core DSM programs to be offered by a statewide Third Party Administrator (TPA) and allowed utilities the option to offer Core Plus programs in an effort to reach the 2% goal.

- As a result, since 2012, a statewide TPA has been running Core DSM Programs in Indiana. In March 2014, the Indiana General Assembly passed legislation which modified DSM requirements in Indiana. Senate Enrolled Act No. 340 ("SEA 340") removed requirements for mandatory statewide "Core' DSM programs and savings requirements established in the Phase II Order. SEA 340 also allows large C&I customers who meet certain criteria to opt-out of participation in utility sponsored DSM programs. Furthermore, the statute goes on to prohibit the Commission from requiring jurisdictional electric utilities to meet the Phase II Order energy savings targets after December 31, 2014 and prohibits jurisdictional electric utilities from renewing or extending an existing contract or entering into a new contract with a statewide third party administrator for an energy efficiency program as established in the Phase II Order.
- As a result of SEA 340, Vectren filed and received approval for a one year DSM plan for 2015 under Cause No. 44495 with a savings target of 1% of eligible customer sales.

VECTREN DSM STRATEGY

Vectren has adopted a cultural change that encourages conservation and efficiency for both its gas and electric customers. Vectren has embraced energy efficiency and actively promotes the benefits of energy efficiency to its employees and customers. Vectren has taken serious steps to implement this cultural change starting with its employees. Vectren encourages each employee, especially those with direct customer contact, to promote conservation. Internal communications and presentations, conservation flyers and handouts, meetings with community leaders, and formal training have all promoted this shift. This cultural shift was a motivating factor in launching a

new Vectren motto of "Live Smart" in order to further emphasize efficiency. Vectren's purpose statement is the foundation of the Vectren Strategy related to DSM:

> *Purpose*
> With a focus on the need to conserve natural resources, we provide energy and related solutions that make our customers productive, comfortable and secure.

Customers are a key component of Vectren's values, and Vectren knows success comes from understanding its customers and actively helping them to use energy efficiently.

Vectren will continue to offer cost-effective DSM to assist customers in managing their energy bills and meet future energy requirements. Vectren will include an on-going level of Vectren sponsored DSM in the load forecast and will also consider additional DSM as a source of new supply in meeting future electric service requirements (discussed further in the IRP DSM modeling section of this chapter). DSM savings levels in the load forecast include DSM energy efficiency programs available to all customer classes and a 1% annual savings targets for 2015-2019 and .5% annually thereafter. The 1% of eligible annual savings target assumes that 70% of eligible large customer load will opt-out of DSM programs using the provision provided in SEA340.[1] The load forecast also includes an ongoing level of energy efficiency related to codes and standards embedded in the load forecast projections. Ongoing DSM is also important given the integration of Vectren's gas and electric efficiency programs.

DSM PLANNING PROCESS

The following outlines Vectren's planning process in support of Vectren's strategy to identify cost effective energy efficiency resources. In 2006, as a result of a settlement in

[1] Vectren assumes that 80% of large customers will opt out of Vectren sponsored DSM programs; however, 70% was selected for large sales modeling to capture large customer energy efficiency projects outside of Vectren sponsored programs.

Cause No. 42861, the DSM Collaborative was formed, including Vectren and the Indiana Office of Utility Consumer Counselor ("OUCC") as voting members. The Collaborative provided input in the planning of Vectren's proposed DSM programs. The Oversight Board was formed as a result of Cause No. 43427 and was given authority to govern Vectren'sElectric DSM Programs. When formed, the Oversight Board included Vectren and the OUCC as voting members. The Citizens Action Coalition ("CAC") was added as a voting member of the Oversight Board in 2013 as a result of Cause No. 44318.

The IURC Phase II Order in Cause No. 42693 issued on December 9, 2009 established energy saving goals for all jurisdictional utilities in Indiana. The Phase II Order required all jurisdictional utilities to implement five specified programs, which the Commission termed Core Programs. The Core Programs were administered by a third party administrator (TPA) selected through a process involving the Demand Side Coordination Committee composed of jurisdictional Investor-Owned Utilities (IOU's) and other pertinent key stakeholders.

Additionally, the Commission recognized that achieving the goals set out in the Phase II Order would not be possible with Core Programs alone and encouraged the utilities to implement Core Plus Programs to assist in reaching the annual savings goals. Core Plus programs are those programs implemented by the jurisdictional electric utilities in Indiana designed to fill the gap between savings achieved by the Core programs and the savings targets established by the Commission in the Phase II Order. To develop its own set of Core Plus programs, Vectren modified existing programs approved in Cause No. 43427 and added new programs, which were approved on August 31, 2011 in Cause No. 43938. During this period, Vectren also proceeded to integrate some of its electric programs with existing gas DSM programs.

However, with the passage of SEA 340, mandatory statewide "Core" DSM programs and savings requirements established in the Phase II Order have been removed as of

December 31, 2014 and large C&I customers who meet certain criteria ("Qualifying Customers") are allowed to opt-out of participation in Company sponsored energy efficiency programs. As a result, Vectren has implemented an opt-out process as defined in IURC Cause No. 44441 to allow Qualifying Customers to opt-out. This process includes defined annual opt-out and opt-in periods. The plan that Vectren initially filed for 2015 in IURC Cause No. 44495 on May 31, 2014 assumed a 50% level of opt-out. During the initial opt-out period effective July 1, 2014, approximately 71% of eligible large C&I retail sales opted out of participation in Company sponsored DSM. The higher than anticipated opt-out required Vectren to adjust the 2015 Plan to reflect lower spending and lower available savings potential because of the additional portion of the load that is no longer participating in DSM programs. There is an additional opt-out period in the fall of 2014 effective January 1, 2015. As a result, Vectren revised the 2015 Plan to adjust for an 80% opt-out level effective January 1, 2015. The revised plan was approved by the Oversight Board and is still pending Commission approval as part of Cause No. 44495.

The 2015 Plan was developed during an IRP planning period; therefore, the 2014 IRP could not serve as a key input into the 2015 Plan. As a result, the avoided cost basis from the 2011 IRP was used to develop the 2015 Plan. The framework for the 2015 Plan is a continuation of programs offered in 2014, at a savings level of 1.2% of sales (adjusted for the assumption that 80% of Qualifying Customers will opt-out of the programs). However, there were many steps involved in developing the 2015 Plan. The objective of these steps was to develop a plan based on market-specific information for Vectren, which could be successfully implemented utilizing realistic assessments of achievable market potential.

The first step in the process was retaining EnerNOC to complete a Market Potential Study[1] (MPS), included in the Technical Appendix, section D. At the end of 2012,

[1] Electric Demand Side Management: Market Potential Study and Action Plan, EnerNOC Utility Solutions Consulting, April 22, 2013

Vectren, with guidance from the Vectren Electric Oversight Board, engaged EnerNOC, Inc. to study its DSM market potential and develop an Action Plan. EnerNOC conducted a detailed, bottom-up assessment of the Vectren market in the Evansville metropolitan area to deliver a projection of baseline electric energy use, forecasts of the energy savings achievable through efficiency measures, and program designs and strategies to optimally deliver those savings. The study developed technical, economic and achievable potential estimates by sector, customer type and measure. According to the MPS, EnerNOC performed the following tasks in completing the study:

1. Conducted onsite energy consumption surveys with 30 of Vectren's largest commercial and industrial customers in order to provide data and guidance for these market sectors that had not formerly received focused DSM program efforts.
2. Performed a market characterization to describe sector-level electricity use for the residential, commercial, and industrial sectors for the base year, 2011. This included using existing information contained in prior Vectren and Indiana studies, new information from the aforementioned onsite surveys with large customers, EnerNOC's own databases and tools, and other secondary data sources such as the American Community Survey (ACS) and the Energy Information Administration (EIA).
3. Developed a baseline electricity forecast by sector, segment, and end use for 2011 through 2023. Results presented in this volume focus on the upcoming implementation years of 2015 through 2019.
4. Identified several hundred measures and estimated their effects in five tiers of measure-level energy efficiency potential: Technical, Economic, Achievable High, Achievable Recommended and Achievable Low.
5. Reviewed the current programs offered by Vectren in light of the study findings to make strategic program recommendations for achieving savings.
6. Created recommended program designs and action plans through 2019 representing the program potential for Vectren, basing them on the potential analysis and strategic recommendations developed in the previous steps.

The EnerNOC MPS and other study information were used to help guide the plan design. Study analysis and results details can be found in the MPS and its appendices. For planning purposes Vectren used the "Recommended Achievable" scenario as a guide for developing the 2015 Plan.

The second primary step in the planning process was to hire outside expertise to assist with the plan design and development. Vectren retained Morgan Marketing Partners to assist with designing the 2015 Plan. Rick Morgan, President of Morgan Marketing Partners, was the primary planner working with the Vectren team.

The third primary step in the planning process was to obtain input from various sources to help develop and refine a workable plan. The first group providing input was Vectren's DSM Program Managers who have been overseeing current Vectren programs. In addition, vendors and other implementation partners who operate the current programs were very involved in the process as well. They provided suggestions for program changes and enhancements. The vendors and partners also provided technical information about measures to include recommended incentives, estimates of participation and estimated implementation costs. These data provided a foundation for the 2015 Plan based on actual experience within Vectren's territory. These companies also bring their experience operating programs for other utilities.

Other sources of program information were also considered. Current evaluations were used for adjustments to inputs. In addition, best practices were researched and reviewed to gain insights into the program design of successful DSM programs implemented at other utilities. Once the plan was developed, Vectren obtained feedback and approval from the Oversight Board before finalizing.

DSM SCREENING RESULTS

The last step of the planning process was the cost benefit analysis. Utilizing a cost / benefit model, the measures and programs were analyzed for cost effectiveness. The outputs include all the California Standard Practice Manual results including Total Resource Cost (TRC), Utility Cost Test (UCT), Participant and Ratepayer Impact Measure (RIM) tests. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure, escalation rates and discount rates. Vectren considers the following tests and ensures that the portfolio passes the TRC test as this test includes the total costs and benefits to both the utility and the consumer. Table 8-4 below outlines the results of all tests.

The model includes a full range of economic perspectives typically used in energy efficiency and DSM analytics. The perspectives include:

- Participant Test
- Utility Cost Test
- Ratepayer Impact Measure Test
- Total Resource Cost Test

The cost effectiveness analysis produces two types of resulting metrics:

1. Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
2. Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

As stated above, the cost effectiveness analysis reflects four primary tests. Each reflects a distinct perspective and has a separate set of inputs reflecting the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test is shown below in Table 8-1.

Table 8-1 Vectren Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

The Participant Cost Test shows the value of the program from the perspective of the utility's customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.

The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The Total Resource Cost (TRC) Test shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.

In completing the tests listed above, Vectren used 7.29% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on April 27, 2011 in Cause No. 43839. For the 2015 Plan, Vectren utilized the avoided costs from Table 8-4 in the 2011 IRP. The avoided costs listed below in Table 8-2 were not yet available when the 2015 Plan was developed and filed with the Commission. As the 2015 Action Plan is finalized in late 2014, Vectren will use the avoided costs from the table below and also for any future modeling of DSM programs for 2016 and beyond. Vectren conducts IRPs every two years. Note that The avoided generating capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance cost for an F-class simple cycle gas turbine, as discussed in Table 6-1 SGCT Classes. The operating and capital costs are assumed to escalate with inflation throughout the study period. The cost assumptions can be found in the Technical Appendix, section B. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost. Vectren's planning reserve margin position is not factored into the avoided capacity cost as presented. Under the base sales forecast, Vectren does not require additional capacity to meet the planning reserve margin requirement throughout the study period.

The marginal energy cost are reflective of the modeled Vectren system marginal cost of energy from the base scenario under base assumptions. This included variable transaction purchase, emission costs for CO_2 starting in 2020, operation and maintenance, and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses. The variable system costs reflected in this calculation can be found in the Technical Appendix, section B.

Table 8-2 Vectren Avoided Costs

	Capacity Surplus / (Deficit)	Generation Avoided Cost	Transmission / Distribution Avoided Cost	Total Capacity Avoided Cost	Marginal Energy Cost	Marginal Energy Cost
	MW	$/kW	$/kW	$/kW	$/MWh	$/kWh
2015	81	$104.01	$10.40	$114.41	$36.94	$0.0369
2016	80	$105.67	$10.57	$116.24	$43.32	$0.0433
2017	102	$107.36	$10.74	$118.10	$45.01	$0.0450
2018	106	$109.08	$10.91	$119.99	$47.58	$0.0476
2019	109	$110.82	$11.08	$121.91	$49.42	$0.0494
2020	109	$112.60	$11.26	$123.86	$63.16	$0.0632
2021	109	$114.40	$11.44	$125.84	$65.23	$0.0652
2022	108	$116.23	$11.62	$127.85	$67.44	$0.0674
2023	108	$118.09	$11.81	$129.90	$69.84	$0.0698
2024	108	$119.98	$12.00	$131.98	$73.54	$0.0735
2025	109	$121.90	$12.19	$134.09	$76.04	$0.0760
2026	109	$123.85	$12.38	$136.23	$79.06	$0.0791
2027	108	$125.83	$12.58	$138.41	$81.84	$0.0818
2028	106	$127.84	$12.78	$140.63	$85.11	$0.0851
2029	105	$129.89	$12.99	$142.88	$89.11	$0.0891
2030	104	$131.97	$13.20	$145.16	$92.79	$0.0928
2031	104	$134.08	$13.41	$147.49	$96.21	$0.0962
2032	102	$136.22	$13.62	$149.85	$100.77	$0.1008
2033	101	$138.40	$13.84	$152.24	$105.98	$0.1060
2034	100	$140.62	$14.06	$154.68	$110.93	$0.1109

A review of the benefit/cost results for each of the technologies considered in the screening analysis is detailed in Table 8-3. Note that measures with a benefit-cost ration of 0.00 indicates no direct technology costs are applied.

Table 8-3 Vectren DSM Technology Screening Results

Residential Technology Analysis Results

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
1	30% Infil. Reduction Electric Furnace no CAC V IQW109	$458	N/A	$118	1.11	$785	3.17	$785	3.17
2	30% Infil. Reduction Electric Furnace w/ CAC V IQW107	$55,076	N/A	$15,424	1.13	$95,634	3.23	$95,634	3.23
3	30% Infil. Reduction Gas Furnace no CAC V IQW111	$55	N/A	($558)	0.18	($478)	0.21	($478)	0.21
4	30% Infil. Reduction Gas Furnace w/ CAC	$19,901	N/A	($58,161)		($29,178)		($29,178)	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	V IQW110				0.44		0.61		0.61
5	30% Infil. Reduction Heat Pump V IQW108	$6,012	N/A	$226	1.02	$8,981	2.63	$8,981	2.63
6	5th Grade Kit- Air Filter Alarm V RES113	$16,471	N/A	$8,159	1.29	$31,187	7.34	$31,187	7.34
7	5th Grade Kit- Bathroom Aerator 1.0 gpm V RES110	$5,758	N/A	$671	1.07	$7,862	3.52	$7,862	3.52
8	5th Grade Kit- CFL - 13 W V RES111	$40,416	N/A	($28,761)	0.61	$15,287	1.51	$15,287	1.51
9	5th Grade Kit- CFL - 23 W V RES112	$65,788	N/A	($43,510)	0.63	$28,191	1.63	$28,191	1.63
10	5th Grade Kit- Kitchen Flip Aerator 1.5 gpm V RES109	$2,879	N/A	($1,431)	0.79	$2,165	1.65	$2,165	1.65
11	5th Grade Kit- LED Nightlight V RES114	$16,172	N/A	($15,326)	0.50	$4,874	1.46	$4,874	1.46
12	5th Grade Kit- Low Flow Showerhead 1.5 gpm V RES108	$35,128	N/A	($7,034)	0.89	$31,250	2.29	$31,250	2.29
13	Air Source Heat Pump 16 SEER - no gas available REP113	($7,347)	0.57	($2,518)	0.77	($2,546)	0.77	$1,427	1.20
14	Air Source Heat Pump 16 SEER -gas available REP127	($8,537)	0.50	($1,328)	0.87	($2,546)	0.77	$2,617	1.44
15	Air Source Heat Pump 18 SEER - gas available REP129	($2,249)	0.46	$127	1.05	($1,032)	0.73	$1,450	2.04
16	Air Source Heat Pump 18 SEER - no gas available REP115	($2,074)	0.51	($48)	0.98	($1,032)	0.73	$1,275	1.81
17	Appliance Recycling Freezers ARC102	$84,943	5.32	($298)	1.00	$63,369	2.69	$63,612	2.71
18	Appliance Recycling Refrigerators ARC101	$385,674	5.90	($3,125)	0.99	$269,452	2.67	$268,064	2.64
19	Attic Insulation V IQW112	$3,288	N/A	($13,850)	0.35	($9,061)	0.46	($9,061)	0.46
20	Audit Recommendations IQW V IQW114	$11,374	N/A	($40,699)	0.29	($29,325)	0.36	($29,325)	0.36
21	Audit Recommendations V HEA116	$28,561	N/A	($69,232)	0.35	($44,098)	0.45	($44,098)	0.45
22	Bathroom Aerator IQW V IQW103	$2,874	N/A	($615)	0.90	$3,125	2.21	$3,125	2.21
23	Bathroom Aerator V HEA112	$37,299	N/A	$3,890	1.06	$46,598	3.48	$46,598	3.48
24	Central Air Conditioner 16 SEER REP 116	($21,517)	0.75	($19,160)	0.73	($4,056)	0.93	$3,801	1.08
25	Central Air Conditioner 18 SEER REP 117	($40,415)	0.68	($11,391)	0.89	($19,244)	0.83	$28,384	1.43
26	CFL 0-15W RLT104	$611,084	3.01	($105,148)	0.84	$300,024	2.27	$347,738	2.85
27	CFL 16-20W RLT105	$619,795	3.46	($77,706)	0.87	$320,977	2.55	$360,400	3.15
28	CFL 21W or Greater RLT106	$591,307	4.09	($55,275)	0.90	$314,606	2.85	$344,554	3.46
29	Compact Fluorescent Lamps V HEA101	$309,769	N/A	($390,021)	0.45	($80,547)	0.80	($80,547)	0.80
30	Compact Fluorescent Lamps IQW V IQW101	$69,004	N/A	($127,952)	0.38	($49,613)	0.62	($49,613)	0.62
31	Dual Fuel Air Sourc Heat Pump 16 SEER REP128	($8,537)	0.50	($1,328)	0.87	($2,546)	0.77	$2,617	1.44
32	Duct Sealing Electric Heat Pump REP108	$20,945	1.89	$5,993	1.10	$38,174	2.27	$36,074	2.13
33	Duct Sealing Electric Resistive Furnace REP109	$10,758	4.42	($1,045)	0.95	$13,411	2.65	$13,131	2.56
34	Duct Sealing Gas Heating with A/C REP107	$1,482	1.02	$49,405	1.46	$77,922	1.99	$101,547	2.84
35	Ductless Heat Pump 17 SEER 9.5 HSPF REP123	$2,469	2.84	($1,590)	0.73	$1,603	1.61	$1,628	1.63
36	Ductless Heat Pump 19 SEER 9.5 HSPF REP124	$1,819	1.90	($1,508)	0.74	$1,174	1.37	$1,735	1.67
37	Ductless Heat Pump 21 SEER 10.0 HSPF REP125	$790	1.59	($904)	0.71	$391	1.21	$765	1.51
38	Ductless Heat Pump 23 SEER 10.0 HSPF REP126	$461	1.27	($869)	0.73	$165	1.08	$808	1.54

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
39	Duel Fuel Air Source Heat Pump 18 SEER REP130	($2,249)	0.46	$127	1.05	($1,032)	0.73	$1,450	2.04
40	ECM HVAC Motor REP118	$9,831	1.11	($49,672)	0.56	($17,936)	0.78	($8,311)	0.88
41	Energy Star Ceiling Fans RLT112	($165)	0.74	($59)	0.84	($29)	0.91	$172	2.26
42	Energy Star Fixtures RLT111	$4,481	1.15	($3,400)	0.88	$8,869	1.54	$15,622	2.63
43	Energy Star Reflector CFL V RLT102	$4,738	1.14	($10,011)	0.65	($1,997)	0.90	$8,065	1.78
44	Energy Star Reflector LED V RLT103	$4,345	1.72	($1,530)	0.87	$5,336	2.01	$7,749	3.70
45	Energy Star Specialty CFL V RLT101	$4,738	1.14	($10,011)	0.65	($1,997)	0.90	$8,065	1.78
46	Furnace Filter Whistle IQW V IQW106	$20,061	N/A	$3,847	1.09	$33,063	3.59	$33,063	3.59
47	Gold Star HERS =<67 All Electric RNC105	$524	1.04	($8,690)	0.71	($1,425)	0.94	$7,088	1.49
48	Gold Star HERS =<67 Electric RNC102	$25,046	2.59	($19,160)	0.78	$24,432	1.55	$26,821	1.64
49	Heat Pump Water Heater REP103	$19,345	1.72	($19,604)	0.74	$8,378	1.18	$21,083	1.62
50	Kitchen Aerator IQW V IQW102	$1,848	N/A	($592)	0.86	$1,812	1.97	$1,812	1.97
51	Kitchen Aerator V HEA111	$37,299	N/A	$3,140	1.05	$45,848	3.35	$45,848	3.35
52	LED 13W RLT109	($1,754)	0.95	($5,037)	0.87	$4,357	1.14	$21,940	2.68
53	LED 22W RLT110	$8,841	1.38	$485	1.01	$18,092	1.90	$29,324	4.29
54	LED 7W RLT107	($2,968)	0.78	($2,138)	0.82	($1,314)	0.88	$5,270	2.11
55	LED 9W RLT108	($5,610)	0.75	($4,383)	0.77	($3,977)	0.78	$6,693	1.87
56	LF Showerhead (Whole House) IQW V IQW104	$18,274	N/A	($10,072)	0.75	$10,674	1.53	$10,674	1.53
57	LF Showerhead (Whole House) V HEA113	$99,709	N/A	($36,798)	0.80	$62,816	1.76	$62,816	1.76
58	Opower OPO101	$487,718	N/A	($188,368)	0.79	$299,349	1.73	$299,349	1.73
59	Pipe Wrap (10', 3/4" Wall) IQW V IQW105	$12,656	N/A	$1,510	1.05	$19,942	3.21	$19,942	3.21
60	Pipe Wrap (5', 3/4" Wall) V HEA114	$28,728	N/A	($6,586)	0.90	$30,232	2.10	$30,232	2.10
61	Platinum Star- EPAct Tax Credit All Electric RNC106	$591	1.13	($3,351)	0.71	($165)	0.98	$2,776	1.50
62	Platinum Star- EPAct Tax Credit Electric RNC103	$10,104	1.60	($12,332)	0.78	$9,998	1.29	$17,159	1.62
63	Pool Heater REP111	$9,209	1.31	($3,752)	0.93	$12,595	1.37	$27,184	2.40
64	programmable thermostat REP104	$37,956	4.10	$30,849	1.41	$78,387	3.90	$81,187	4.36
65	Refrigerator Replacement IQW V IQW113	$195,980	N/A	($51,141)	0.91	$245,594	1.98	$245,594	1.98
66	Siver Star HERS =<75 All Electric RNC104	$3,935	2.61	($4,059)	0.72	$2,951	1.40	$3,588	1.53
67	Siver Star HERS =<75 Electric RNC101	$10,658	3.15	($7,321)	0.79	$10,766	1.65	$11,274	1.71
68	Smart programmable thermostat REP120	$54,240	2.55	$62,384	1.46	$135,466	3.19	$145,966	3.83
69	Variable Speed Pool Pump REP110	$6,147	1.12	$48,252	1.58	$66,439	2.02	$87,439	2.99
70	Water Heater Tank Wrap HEA117	$31,284	N/A	($35,875)	0.56	($4,620)	0.91	($4,620)	0.91

Measures with a benefit-cost ration of 0.00 indicates no direct technology costs are applied.

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
1	Anti Sweat - Cooler V CDI101	$53,689	2.18	($39,109)	0.70	$34,169	1.61	$34,169	1.61
2	Anti Sweat - Freezer V CDI102	$33,647	3.96	($7,383)	0.88	$38,540	3.14	$38,540	3.14
3	Barrel Wraps (Inj Mold Only) CIP202	$5,727	6.73	$206	1.03	$5,561	4.57	$5,861	5.65
4	CFL 16-20W Fixture 1 Lamp CIE142	$5,798	2.43	$678	1.06	$8,088	3.09	$10,178	6.69
5	CFL 16-20W Fixture 2 Lamp CIE145	$15,079	4.25	$1,355	1.06	$18,962	4.81	$20,355	6.69
6	CFL 21W+ Fixture 1 Lamp CIE143	$4,265	3.10	$487	1.07	$5,672	3.79	$6,601	7.00
7	CFL 21W+ Fixture 2 Lamp CIE146	$10,271	5.42	$974	1.07	$12,738	5.78	$13,202	7.00
8	CFL Fixture, Direct Install, 18 Watt, Exterior V CDI103	$3,376	N/A	($1,047)	0.86	$3,561	2.35	$3,561	2.35
9	CFL Fixture, Direct Install, 36 Watt, Interior V CDI104	$17,933	N/A	($931)	0.97	$23,544	3.51	$23,544	3.51
10	CFL screw-in: <30W V CDI105	$38,152	N/A	($15,939)	0.76	$24,794	1.94	$24,794	1.94
11	CFL <15W Fixture 1 Lamp CIE141	$2,655	1.65	$295	1.04	$4,295	2.17	$6,617	5.91
12	CFL <15W Fixture 2 Lamp CIE144	$8,794	2.89	$590	1.04	$11,376	3.50	$13,234	5.91
13	Clothes Washer CEE Tier 2 CIP244	($139)	0.71	($21)	0.94	($53)	0.87	$267	4.22
14	Clothes Washer CEE Tier 3 CIP245	($258)	0.57	($31)	0.92	($157)	0.69	$257	3.76
15	Clothes Washer ENERGY STAR/CEE Tier 1 CIP243	($10)	0.94	($5)	0.97	$25	1.16	$138	4.80
16	Cooler - Glass Door 15-30 vol CIP224	$297	3.39	$3	1.01	$361	3.79	$433	8.54
17	Cooler - Glass Door 30-50 vol CIP225	$435	6.30	$7	1.01	$503	5.91	$539	9.05
18	Cooler - Glass Door <15 vol CIP223	$220	4.07	($5)	0.99	$254	4.28	$286	7.32
19	Cooler - Glass Door >50 vol CIP226	$753	10.18	$26	1.03	$869	7.88	$900	10.39
20	Cooler - Reach-In Electronically Commutated (EC) Motor CIP238	$1,773	4.55	($118)	0.96	$2,081	4.87	$2,181	5.99
21	Cooler - Solid Door 15-30 vol CIP220	$149	1.60	($29)	0.94	$202	1.90	$346	5.27
22	Cooler - Solid Door 30-50 vol CIP221	$361	5.40	$2	1.00	$417	5.30	$452	8.37
23	Cooler - Solid Door <15 vol CIP219	$91	2.28	($14)	0.92	$104	2.54	$136	4.84
24	Cooler - Solid Door >50 vol CIP222	$576	8.03	$13	1.02	$663	6.87	$693	9.42
25	Cooler - Walk-In Electronically Commutated (EC) Motor CIP235	$1,462	4.90	($100)	0.96	$1,703	5.13	$1,778	6.27
26	Cooler Anti-Sweat Heater Controls - Conductivity-Based CIP216	$239	2.19	$19	1.04	$334	2.76	$444	6.58
27	Cooler Anti-Sweat Heater Controls - Humidity-Based CIP215	$28	1.19	$2	1.01	$74	1.56	$169	5.62
28	Cooler Controller - occupancy sensor V CDI106	$16,843	6.91	($1,002)	0.97	$21,128	4.18	$21,840	4.68
29	Delamping, T12 to T8, 4' V CDI108	$59,889	N/A	$16,927	1.18	$98,666	9.71	$98,666	9.71
30	Delamping, T12 to T8, 8' V CDI109	$24,811	N/A	$7,020	1.18	$40,883	9.71	$40,883	9.71
31	Delamping, >=400 Watt Fixture V CDI107	$48,989	N/A	$13,958	1.18	$80,821	9.71	$80,821	9.71
32	Demand Controlled Ventilation - CO CIP165	$961	4.34	$383	1.25	$1,589	6.14	$1,704	9.79
33	Demand Controlled Ventilation - CO2 CIP164	$1,922	4.34	$766	1.25	$3,177	6.14	$3,407	9.79
34	Door Closers for Cooler CDI142	$16,426	2.07	($16,277)	0.61	$2,205	1.09	$6,033	1.31

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
35	Door Closers for Freezer CDI143	$45,048	3.94	($23,049)	0.73	$26,959	1.78	$30,788	2.00
36	EC Motor Reach-in V CDI110	$8,130	2.14	($3,488)	0.84	$9,163	2.03	$10,939	2.53
37	EC Motor Walk-in V CDI111	$8,309	1.70	($6,787)	0.75	$6,664	1.48	$9,624	1.88
38	EDA - Lighting Power Density Reduction CNC101	$41,883	1.24	$3,144	1.01	$124,901	1.54	$260,146	3.76
39	EDA - Non Lighting Measures CNC102	($41,916)	0.73	($49,757)	0.72	($61,110)	0.68	$69,363	2.18
40	Electric Chiller - Air cooled, with condenser CIP156	$150	2.81	$125	1.42	$347	5.40	$383	9.92
41	Electric Chiller - Air cooled, without condenser CIP157	($25)	0.40	$14	1.66	$0	1.01	$28	5.96
42	Electric Chiller - Water Cooled, Centrifugal 150-300 tons CIP162	$28	1.60	$30	1.32	$83	3.04	$105	6.59
43	Electric Chiller - Water Cooled, Centrifugal <150 tons CIP161	$24	1.39	$37	1.34	$94	2.73	$129	7.59
44	Electric Chiller - Water Cooled, Centrifugal >300 tons CIP163	$76	2.10	$54	1.29	$175	3.80	$201	6.38
45	Electric Chiller - Water Cooled, Rotary Screw 150-300 tons CIP159	$45	2.51	($13)	0.87	$55	2.98	$64	4.38
46	Electric Chiller - Water Cooled, Rotary Screw <150 tons CIP158	$29	1.69	$41	1.46	$94	3.54	$112	7.05
47	Electric Chiller - Water Cooled, Rotary Screw >300 tons CIP160	$53	3.52	$31	1.33	$104	6.07	$106	6.64
48	Electric Chiller Tune-up - Air cooled, with condenser CIP172	$24	3.17	$7	1.18	$30	3.34	$35	5.36
49	Electric Chiller Tune-up - Water Cooled, Centrifugal 150-300 tons CIP178	$9	1.82	$1	1.06	$11	2.01	$16	3.76
50	Electric Chiller Tune-up - Water Cooled, Centrifugal >300 tons CIP179	$8	1.70	$1	1.04	$9	1.88	$14	9.92
51	Electric Chiller Tune-up - Water Cooled, Rotary Screw 150-300 tons CIP175	$10	1.89	$1	1.03	$11	2.02	$16	5.96
52	Electric Chiller Tune-up - Water Cooled, Rotary Screw >300 tons CIP176	$8	1.76	$1	1.07	$11	1.98	$15	7.59
53	ENERGY STAR CEE Tier 1 Window\Sleeve\Room AC < 14,000 BTUH CIP118	$6	1.15	$33	1.63	$51	2.45	$75	7.87
54	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC < 14,000 BTUH CIP170	($82)	0.34	$54	2.12	($0)	1.00	$75	8.19
55	ENERGY STAR CEE Tier 2 Window\Sleeve\Room AC >= 14,000 BTUH CIP171	($181)	0.27	$101	2.29	($25)	0.88	$75	11.68
56	ENERGY STAR Commercial Dishwasher - Door Type, High Temp CIP249	$4,292	18.17	$501	1.09	$5,552	12.13	$5,502	11.03
57	ENERGY STAR Commercial Dishwasher - Multi-Tank Conveyor, Low Temp CIP252	$5,646	12.64	$884	1.11	$8,216	11.86	$8,229	12.06
58	ENERGY STAR Commercial Dishwasher - Under Counter, High Temp CIP247	$1,580	4.16	$12	1.00	$1,769	4.17	$1,994	6.99
59	ENERGY STAR Commercial Dishwasher - Under Counter, Low Temp CIP246	$119	1.45	($45)	0.89	$140	1.59	$277	3.75
60	ENERGY STAR Commercial Fryer CIP103	$78	1.31	$22	1.06	$175	1.79	$325	5.60
61	ENERGY STAR Commercial Hot Holding Cabinets Full Size CIP104	$1,195	3.15	($1)	1.00	$1,443	3.60	$1,637	5.53
62	ENERGY STAR Commercial Hot Holding Cabinets Half Size CIP105	$101	1.18	($34)	0.95	$227	1.47	$546	4.32
63	ENERGY STAR Commercial Hot Holding Cabinets Three Quarter Size CIP106	$432	1.78	($37)	0.97	$581	2.15	$850	4.61

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
64	ENERGY STAR Commercial Ice Machine < 500 lb/day harvest rate CIP114	($123)	0.54	($42)	0.73	($110)	0.51	$55	1.94
65	ENERGY STAR Commercial Ice Machine >=1000 lb/day harvest rate CIP116	($471)	0.53	($91)	0.84	($355)	0.58	$323	3.01
66	ENERGY STAR Commercial Ice Machine >=500 and <1000 lb/day harvest rate CIP115	($4,241)	0.43	($685)	0.80	($3,406)	0.45	$1,659	2.54
67	ENERGY STAR Commercial Steam Cookers 3 Pan CIP107	$1,123	1.32	$36	1.01	$2,215	1.72	$4,265	5.14
68	ENERGY STAR Commercial Steam Cookers 4 Pan CIP108	$2,419	1.69	$4	1.00	$3,575	2.13	$5,375	4.96
69	ENERGY STAR Commercial Steam Cookers 5 Pan CIP109	$2,214	2.27	$64	1.01	$2,934	2.79	$3,709	5.28
70	ENERGY STAR Commercial Steam Cookers 6 Pan CIP110	$2,957	2.69	$72	1.01	$3,743	3.22	$4,393	5.23
71	ENERGY STAR Convection Oven CIP111	$564	2.01	$16	1.01	$779	2.52	$1,049	5.31
72	ENERGY STAR Griddles CIP112	$1,348	2.29	$65	1.02	$1,810	2.84	$2,296	5.61
73	ENERGY STAR Window\Sleeve\Room AC < 14,000 BTUH CIP117	$24	2.20	$35	1.70	$67	4.53	$77	9.64
74	ENERGY STAR Window\Sleeve\Room AC >= 14,000 BTUH CIP119	$47	3.35	$58	1.75	$114	6.57	$123	11.69
75	Faucet Aerators-electric V CDI112	$2,777	N/A	($235)	0.95	$3,378	4.33	$3,378	4.33
76	Fluorescent Exit Sign To LED Exit Sign CIE135	$40,257	2.47	($10,427)	0.87	$44,602	2.78	$48,247	3.25
77	Freezer - Glass Door 15-30 vol CIP232	$611	8.36	($28)	0.97	$657	6.79	$648	6.31
78	Freezer - Glass Door 30-50 vol CIP233	$1,242	15.97	($6)	1.00	$1,366	9.56	$1,332	7.90
79	Freezer - Glass Door <15 vol CIP231	$351	5.94	($21)	0.96	$378	5.44	$385	5.92
80	Freezer - Glass Door >50 vol CIP234	$2,357	12.58	$8	1.00	$2,625	8.63	$2,612	8.33
81	Freezer - Reach-In Electronically Commutated (EC) Motor CIP237	$228	5.57	($13)	0.96	$266	5.65	$276	6.84
82	Freezer - Solid Door 15-30 vol CIP228	$665	9.01	($23)	0.97	$720	7.12	$711	6.64
83	Freezer - Solid Door 30-50 vol CIP229	$872	11.50	($34)	0.97	$932	8.10	$899	6.45
84	Freezer - Solid Door <15 vol CIP227	$262	4.68	($28)	0.93	$273	4.49	$280	4.92
85	Freezer - Solid Door >50 vol CIP230	$1,497	8.36	($58)	0.97	$1,620	6.81	$1,608	6.53
86	Freezer - Walk-In Electronically Commutated (EC) Motor CIP236	$916	8.33	($76)	0.94	$1,020	7.16	$1,020	7.16
87	Freezer Anti-Sweat Heater Controls - Conductivity-Based CIP218	$362	4.62	$23	1.04	$443	4.98	$473	6.82
88	Freezer Anti-Sweat Heater Controls - Humidity-Based CIP217	$249	2.66	($17)	0.96	$291	3.01	$336	4.37
89	Halogen 120W x3 To CMH 150W - Retrofit CIE134	$14,364	6.00	$2,071	1.10	$19,539	6.90	$19,923	7.80
90	Halogen 120W x3 To CMH 150W - Turnover CIE115	$15,464	5.77	$3,054	1.13	$22,016	6.90	$23,168	9.97
91	Halogen 50W x2 To CMH 20W - Retrofit CIE129	$2,561	1.62	$539	1.07	$4,881	2.32	$7,245	6.41
92	Halogen 50W x2 To CMH 20W - Turnover CIE110	$2,706	1.58	$787	1.09	$5,500	2.32	$8,344	7.28
93	Halogen 50W x2 To MH 20W Track - Retrofit CIE126	$618	1.40	$186	1.07	$1,418	2.05	$2,348	6.59
94	Halogen 50W x2 To MH 20W Track - Turnover CIE107	$3,036	1.40	$912	1.07	$6,959	2.05	$11,527	6.59
95	Halogen 65W x3 To CMH 50W - Retrofit CIE131	$9,293	4.06	$1,395	1.09	$13,093	5.16	$14,083	7.53

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
96	Halogen 65W x3 To CMH 50W - Turnover CIE112	$9,930	3.90	$2,112	1.13	$14,752	5.16	$16,408	9.68
97	Halogen 75W x2 To CMH 39W - Retrofit CIE130	$4,622	2.27	$739	1.07	$7,264	3.15	$9,049	6.70
98	Halogen 75W x2 To CMH 39W - Turnover CIE111	$5,963	2.27	$954	1.07	$9,372	3.15	$11,676	6.70
99	Halogen 75W x2 To MH 39W Track - Retrofit CIE127	$1,441	1.94	$275	1.08	$2,448	2.75	$3,280	6.79
100	Halogen 75W x2 To MH 39W Track - Turnover CIE108	$8,513	1.94	$1,624	1.08	$14,466	2.75	$19,380	6.79
101	Halogen 75W x3 To CMH 70W - Retrofit CIE132	$8,661	4.27	$1,185	1.09	$12,014	5.33	$12,739	7.21
102	Halogen 75W x3 To CMH 70W - Turnover CIE113	$10,456	4.06	$2,249	1.13	$15,502	5.33	$17,158	9.91
103	Halogen 75W x3 To MH 70W Track - Retrofit CIE128	$2,627	2.83	$433	1.09	$3,936	3.84	$4,589	7.28
104	Halogen 75W x3 To MH 70W Track - Turnover CIE109	$15,521	2.83	$2,559	1.09	$23,256	3.84	$27,117	7.28
105	Halogen 90W x3 To CMH 100W - Retrofit CIE133	$11,327	4.94	$1,481	1.09	$15,438	5.94	$15,981	7.19
106	Halogen 90W x3 To CMH 100W - Turnover CIE114	$12,043	4.72	$2,389	1.13	$17,394	5.94	$18,726	9.56
107	Heat Pump Water Heater 10-50 MBH CIP255	$27,103	3.71	$2,908	1.07	$37,311	4.65	$40,311	6.57
108	HID 101W-175W To T5 Garage 2 Lamp CIE159	($6,247)	0.73	($8,549)	0.52	($10,409)	0.47	($1,040)	0.90
109	HID 176W+ To T5 Garage 3 Lamp CIE160	$834	1.07	($6,812)	0.47	($3,827)	0.61	($1,792)	0.77
110	HID 75W-100W To T5 Garage 1 Lamp CIE158	($12,753)	0.46	($4,919)	0.55	($13,185)	0.31	$87	1.01
111	HID To Induction Lamp and Fixture 55-100W CIE204	($616)	0.47	$55	1.08	($245)	0.75	$574	4.95
112	HID To Induction Lamp and Fixture >100W CIE205	($27,147)	0.36	$3,072	1.16	($13,089)	0.62	$18,771	7.30
113	HID >400W to Exterior LED or Induction CIP199	$17	2.10	$5	1.13	$30	3.15	$38	7.61
114	HID >400W to Garage LED or Induction CIP200	$4	2.10	$1	1.13	$8	3.15	$10	7.61
115	High Efficiency Pumps - 1.5hp CIP203	$103	1.29	$45	1.08	$283	1.93	$503	6.85
116	High Efficiency Pumps - 10hp CIP208	$1,846	12.12	$395	1.16	$2,586	11.00	$2,599	11.58
117	High Efficiency Pumps - 15hp CIP209	$2,339	9.00	$541	1.17	$3,350	9.38	$3,444	12.26
118	High Efficiency Pumps - 20hp CIP210	$4,073	5.79	$942	1.16	$5,945	7.03	$6,305	11.07
119	High Efficiency Pumps - 2hp CIP204	$162	1.92	$27	1.07	$271	2.70	$361	6.23
120	High Efficiency Pumps - 3hp CIP205	$471	3.69	$99	1.13	$701	4.92	$781	8.90
121	High Efficiency Pumps - 5hp CIP206	$1,031	7.05	$226	1.15	$1,477	8.00	$1,533	10.92
122	High Efficiency Pumps - 7.5hp CIP207	$1,579	7.34	$370	1.17	$2,284	8.27	$2,384	12.09
123	Incandescent To CFL 16-20W Screw-In CIE139	$5,023	10.61	($532)	0.91	$3,837	3.82	$3,906	4.03
124	Incandescent To CFL 21W+ Screw-In CIE140	$2,230	8.68	($369)	0.86	$1,593	3.50	$1,535	3.21
125	Incandescent To CFL <15W Screw-In CIE138	$7,100	7.80	($960)	0.89	$5,262	3.41	$5,402	3.64
126	Incandescent Traffic Signal To LED Traffic Signal Pedestrian 12" CIE137	$21,726	2.79	($3,430)	0.91	$21,988	2.81	$28,671	6.25
127	Incandescent Traffic Signal To LED Traffic Signal Round 8" Red CIE136	$4,272	1.59	($1,197)	0.91	$4,931	1.75	$8,940	4.45
128	Industrial Request for Proposals - Elec CUS109	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
129	Industrial Staffing Grants - Elec CUS108	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
130	Large Industrial Custom Measure - Non	$116,770		($30,687)		$145,242		$227,929	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	Lighting CUS101		1.89		0.91		1.86		3.63
131	LED A-Line 8-12W CIE162	$10,449	1.99	($2,431)	0.89	$9,009	1.87	$13,755	3.47
132	LED Decoratives 2-4W CIE161	$140	1.23	($172)	0.78	$56	1.10	$335	2.24
133	LED Exterior Wall-Pack 30W-75W CIE174	$2,902	1.36	$366	1.03	$5,720	1.81	$10,512	5.63
134	LED Exterior Wall-Pack 75W+ CIE175	$7,841	1.65	$1,290	1.06	$13,129	2.21	$20,318	6.56
135	LED Exterior Wall-Pack <30W CIE173	$6,377	2.21	$415	1.03	$8,766	2.77	$11,304	5.69
136	LED Fixture <250W, Replacing 400W HID, HighBay V CDI113	$13,142	1.59	($9,928)	0.79	$11,749	1.46	$17,309	1.87
137	LED for Walk in Cooler V CDI114	$10,734	1.19	($33,049)	0.61	($10,205)	0.83	$4,003	1.09
138	LED for Walk in Freezer V CDI115	$5,749	1.20	($16,378)	0.62	($4,388)	0.86	$2,716	1.12
139	LED MR16 4-7W CIE166	$473	1.22	($560)	0.80	$317	1.17	$1,220	2.27
140	LED Open Sign V CDI116	$27,587	4.88	$3,027	1.06	$41,327	4.26	$43,103	4.96
141	LED Outdoor Decora ive Post 30W-75W CIE168	$2,902	1.36	$366	1.03	$5,720	1.81	$10,512	5.63
142	LED Outdoor Decora ive Post 75W+ CIE169	$7,841	1.65	$1,290	1.06	$13,129	2.21	$20,318	6.56
143	LED Outdoor Decorative Post <30W CIE167	$6,377	2.21	$415	1.03	$8,766	2.77	$11,304	5.69
144	LED PAR 20 7-9W CIE163	$928	1.44	($200)	0.94	$1,123	1.58	$2,292	4.03
145	LED PAR 30 10-13W CIE164	$5,141	1.61	($611)	0.96	$6,093	1.78	$10,756	4.42
146	LED PAR 38 10-21W CIE165	$21,522	2.23	($2,793)	0.93	$21,858	2.30	$28,851	3.93
147	LED Parking Garage/Canopy 30W-75W CIE171	$1,921	1.36	$243	1.03	$3,786	1.81	$6,959	5.63
148	LED Parking Garage/Canopy 75W+ CIE172	$5,191	1.65	$854	1.06	$8,691	2.21	$13,450	6.56
149	LED Parking Garage/Canopy <30W CIE170	$4,274	2.21	$278	1.03	$5,875	2.77	$7,576	5.69
150	LED Recessed Downlight V CDI117	$19,708	2.46	($1,564)	0.97	$28,759	2.64	$32,311	3.31
151	LED, Exit Sign, Retrofit V CDI118	$13,304	N/A	($7,931)	0.74	$11,833	2.13	$11,833	2.13
152	LED, Refrigerated Case, Replaces T12 or T8 V CDI119	$29,418	1.30	($74,323)	0.55	($18,547)	0.83	$6,317	1.07
153	LEDs: 8-12W V CDI122	$30,516	N/A	($7,788)	0.86	$29,919	2.54	$29,919	2.54
154	LEDs: 8-12W V CDI123	$17,175	N/A	($4,383)	0.86	$16,840	2.54	$16,840	2.54
155	LEDs: MR16 track V CDI124	$36,993	N/A	($6,825)	0.90	$38,887	2.86	$38,887	2.86
156	LEDs: MR16 track V CDI125	$20,821	N/A	($3,841)	0.90	$21,887	2.86	$21,887	2.86
157	LEDs: >12W Flood V CDI120	$51,786	N/A	($7,940)	0.91	$56,050	3.02	$56,050	3.02
158	LEDs: >12W Flood V CDI121	$19,420	N/A	($2,978)	0.91	$21,019	3.02	$21,019	3.02
159	Low Flow Pre-Rinse Sprayer - Electric CIP242	$3,052	35.87	($52)	0.98	$2,735	6.90	$2,742	7.01
160	Market Segment Programs - Elec CUS105	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
161	MH 1000W Pulse Start To T5 46" 10 Lamp HO - Turnover CIE105	$132,715	8.86	$21,253	1.12	$179,716	9.00	$179,153	8.78
162	MH 1000W Pulse Start To T5 46" 12 Lamp HO - Turnover CIE106	$84,985	6.97	$10,884	1.09	$113,138	7.59	$112,663	7.38
163	MH 1000W To T5 46" 10 Lamp HO - Retrofit CIE124	$132,715	8.86	$21,253	1.12	$179,716	9.00	$179,153	8.78
164	MH 1000W To T5 46" 12 Lamp HO -	$56,388		$7,222		$75,068		$74,753	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	Retrofit CIE125		6.97		1.09		7.59		7.38
165	MH 1000W To T8VHO 48" 8 Lamp (2 fixtures) CIP187	$4,072	6.43	($183)	0.96	$3,880	4.86	$3,855	4.74
166	MH 150W Pulse Start To T5 46" 2 Lamp HO - Turnover CIE101	$5,637	1.24	$2,653	1.08	$17,219	1.83	$32,224	6.73
167	MH 175W To T5 46" 2 Lamp HO - Retrofit CIE120	$17,621	1.74	$2,785	1.06	$30,921	2.45	$43,557	6.05
168	MH 175W To T5 46" 3 Lamp HO - Retrofit CIE121	($6,991)	0.70	($3,617)	0.81	($4,156)	0.79	$8,480	2.21
169	MH 200W Pulse Start To T5 46" 3 Lamp HO - Turnover CIE102	($131)	0.99	$1,153	1.04	$8,998	1.44	$24,003	5.58
170	MH 200W To LED High Bay 139W CIE118	$317	1.04	($694)	0.92	$1,096	1.16	$5,740	3.70
171	MH 250W To LED High Bay 175W CIE119	$12,997	1.34	($4,175)	0.92	$16,097	1.46	$37,432	3.78
172	MH 250W To LED Low Bay 85 W3 CIE116	$10,051	2.30	($1,166)	0.94	$10,264	2.37	$13,360	4.03
173	MH 250W To T8VHO 48" 4 Lamp CIP184	$2,799	1.93	($496)	0.92	$2,720	1.95	$4,120	3.82
174	MH 320W Pulse Start To T5 46" 4 Lamp HO - Turnover CIE103	$47,012	2.39	$9,667	1.10	$75,276	3.37	$93,276	7.79
175	MH 350W Pulse Start To T5 46" 6 Lamp HO - Turnover CIE104	$1,046	1.06	($1,009)	0.95	$5,628	1.39	$14,628	3.72
176	MH 400W To T5 46" 4 Lamp HO - Retrofit CIE122	$108,061	4.20	$12,814	1.08	$147,878	5.21	$155,753	6.72
177	MH 400W To T5 46" 6 Lamp HO - Retrofit CIE123	$36,116	2.07	$3,997	1.05	$56,539	2.83	$72,289	5.78
178	MH 400W To T8VHO 48" 6 Lamp CIP185	$5,930	2.98	($387)	0.96	$5,849	2.86	$7,049	4.62
179	MH 400W To T8VHO 48" 8 Lamp CIP186	$966	2.29	($151)	0.92	$911	2.24	$1,211	3.77
180	Network PC Power Management Software CIP214	$306	3.55	($97)	0.78	$186	2.21	$252	3.89
181	Night Covers V CDI126	$5,769	1.73	($6,168)	0.64	$651	1.06	$2,640	1.31
182	No controls To Ceiling-Mounted Occupancy Sensors CIE180	$50,987	4.48	($10,188)	0.85	$43,051	3.54	$48,110	5.04
183	No controls To Ceiling-Mounted Occupancy Sensors >500W Connected CIP190	$5,164	8.82	($724)	0.88	$4,510	5.46	$4,638	6.25
184	No controls To Central Lighting Controls (Timeclocks) CIE185	$119	1.10	($395)	0.71	($55)	0.95	$591	2.60
185	No controls To Central Lighting Controls (Timeclocks) >500W Connected CIP195	$49	1.95	($20)	0.81	$38	1.77	$69	4.83
186	No controls To Fixture Mounted Daylight Dimming Sensors CIE183	$916	1.66	($20)	0.99	$1,153	1.90	$1,850	4.15
187	No controls To Fixture Mounted Daylight Dimming Sensors >500W Connected CIP193	$10,648	11.65	$1,487	1.12	$12,210	7.91	$12,210	7.91
188	No controls To Fixture Mounted Occupancy Sensors CIE181	($1,238)	0.70	($801)	0.74	($1,233)	0.65	$1,431	2.65
189	No controls To Fixture Mounted Occupancy Sensors >500W Connected CIP191	$9,148	4.66	($1,448)	0.88	$8,075	3.72	$9,275	6.25
190	No controls To LED Case Lighting Sensor Controls CIP196	$2,123	2.63	$99	1.03	$2,446	2.85	$3,186	6.44
191	No controls To Remote-Mounted Daylight Dimming Sensors CIE182	$2,597	4.55	$292	1.08	$3,001	4.53	$3,249	6.38
192	No controls To Remote-Mounted Daylight Dimming Sensors >500W Connected CIP192	$1,293	8.96	$186	1.12	$1,496	6.97	$1,526	7.91
193	No controls To Switching Controls for Multi-Level Lighting CIE184	($5,195)	0.32	($248)	0.90	($3,936)	0.37	$1,622	3.23
194	No controls To Switching Controls for Multi-Level Lighting >500W Connected CIP194	$771	2.13	$122	1.08	$1,015	2.52	$1,463	7.63

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
195	No controls To Wall-Mounted Occupancy Sensors CIE179	$25,210	3.71	($6,241)	0.83	$20,488	3.02	$23,505	4.30
196	No controls To Wall-Mounted Occupancy Sensors >500W Connected CIP189	$5,404	13.87	($724)	0.88	$4,702	6.74	$4,638	6.25
197	Occupancy Sensor, Wall Mount, >200 Watts V CDI128	$46,730	3.19	($16,159)	0.83	$42,841	2.26	$48,172	2.68
198	Occupancy Sensor, Wall Mount, <=200 Watts V CDI127	$6,114	2.15	($4,027)	0.73	$3,842	1.54	$5,176	1.89
199	Outside Air Economizer with Dual-Enthalpy Sensors CIP167	($172)	0.57	($25)	0.90	($109)	0.67	$161	3.49
200	Packaged Terminal Air Conditioner (PTAC) 65,000-135,000 BtuH CIP141	($326)	0.97	$8,588	1.74	$11,611	2.36	$18,111	9.76
201	Packaged Terminal Air Conditioner (PTAC) <65,000 BtuH CIP140	($346)	0.97	$9,198	1.80	$12,198	2.42	$18,698	10.05
202	Packaged Terminal Heat Pump (PTHP) 65,000-135,000 BtuH CIP143	($363)	0.96	$7,591	1.66	$10,572	2.23	$17,072	9.26
203	Packaged Terminal Heat Pump (PTHP) <65,000 BtuH CIP142	($382)	0.96	$8,204	1.71	$11,162	2.30	$17,662	9.55
204	Pellet Dryer Duct Insulation 3in -8in dia CIP201	$839	2.29	($307)	0.80	$553	1.83	$773	2.73
205	Performance Based Industrial Assessments - Elec CUS106	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
206	Plug Load Occupancy Sensors CIP212	$262	1.37	($306)	0.70	$87	1.14	$447	2.65
207	Pre-Rinse Spray Valves - ele V CDI129	$6,301	N/A	($1,263)	0.87	$5,890	3.56	$5,890	3.56
208	Programmable Thermostat CDI137	$647,200	N/A	($113,077)	0.91	$621,676	2.28	$621,676	2.28
209	PSMH 1000W To T8VHO 48" 8 Lamp (2 fixtures) CIP197	$5,683	8.58	$1,298	1.17	$8,143	9.10	$8,443	12.96
210	Refrigerated Case Covers CIP239	$250	1.60	($262)	0.62	$24	1.06	$210	1.97
211	Self-Generation Efficiency Improvements - Elec CUS107	$8,218	1.75	($2,373)	0.91	$10,428	1.75	$17,627	3.63
212	Showerheads-electric V CDI130	$3,016	N/A	($231)	0.95	$3,693	4.42	$3,693	4.42
213	Smart Strip Plug Outlet CIP211	($4)	0.98	($29)	0.81	($4)	0.97	$76	2.52
214	Smart Strips CDI138	$11,467	N/A	($35,603)	0.32	($21,432)	0.44	($21,432)	0.44
215	Snack Machine Controller (Non-refrigerated vending) CIP213	$351	1.32	($296)	0.80	$167	1.17	$731	2.64
216	Specialty CFLs: Reflectors V CDI131	$10,774	N/A	($11,491)	0.55	($353)	0.98	($353)	0.98
217	Split System Heat Pump 135,000-240,000 BtuH CIP149	($228)	0.96	$4,336	1.63	$6,096	2.19	$9,896	8.43
218	Split System Heat Pump 240,000-760,000 BtuH CIP150	($4,412)	0.51	$3,369	1.62	$1,382	1.19	$7,782	8.32
219	Split System Heat Pump 65,000-135,000 BtuH CIP148	($127)	0.96	$2,657	1.66	$3,700	2.23	$5,975	9.26
220	Split System Heat Pump <65,000 BtuH CIP147	($19)	0.96	$410	1.71	$558	2.30	$883	9.55
221	Split System Unitary Air Conditioner 135,000-240,000 BtuH CIP153	($129)	0.97	$3,075	1.71	$4,191	2.31	$6,566	8.89
222	Split System Unitary Air Conditioner 240,000-760,000 BtuH CIP154	($5,494)	0.51	$4,791	1.70	$2,332	1.25	$10,332	8.77
223	Split System Unitary Air Conditioner 65,000-135,000 BtuH CIP152	($245)	0.97	$6,441	1.74	$8,708	2.36	$13,583	9.76
224	Split System Unitary Air Conditioner <65,000 BtuH CIP151	($260)	0.97	$6,899	1.80	$9,149	2.42	$14,024	10.05
225	Split System Unitary Air Conditioner >760,000 BtuH CIP155	($14,058)	0.38	$6,711	1.65	($1,651)	0.91	$14,799	7.63
226	Strip Curtains Cooler CDI144	$656	1.01	($36,333)	0.29	($34,476)	0.30	($23,298)	0.39
227	Strip Curtains Freezer CDI145	$86,941	2.62	($64,121)	0.66	$33,008	1.35	$46,464	1.58

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
228	System Study CUS102	$47,415	7.16	($6,819)	0.91	$53,528	4.27	$50,651	3.63
229	T12 18” 1 Lamp To Delamp CIE147	$1,061	N/A	$42	1.04	$1,141	16.44	$1,019	6.19
230	T12 24” 1 Lamp To Delamp CIE148	$6,891	N/A	$482	1.06	$7,630	16.44	$7,016	7.33
231	T12 36” 1 Lamp To Delamp CIE149	$2,000	N/A	$205	1.09	$2,282	16.44	$2,160	8.99
232	T12 46" 1 Lamp To T5 46" 1 Lamp CIE154	$342	1.22	($106)	0.95	$606	1.45	$1,469	4.00
233	T12 46" 2 Lamp To T5 46" 2 Lamp CIE155	$6,104	2.32	($79)	0.99	$7,318	2.66	$9,348	4.94
234	T12 46" 3 Lamp To T5 46" 3 Lamp CIE156	$7,448	3.43	$105	1.01	$8,538	3.69	$9,521	5.35
235	T12 46" 4 Lamp To T5 46" 4 Lamp CIE157	$22,669	4.69	$702	1.02	$25,627	4.72	$26,856	5.74
236	T12 48” 1 Lamp To Delamp CIE150	$71,597	N/A	$7,541	1.09	$81,894	16.44	$77,671	9.15
237	T12 6' To Refrigerated Display Case Lighting 6' LED - Cooler CIP181	($2,341)	0.63	($568)	0.86	($1,692)	0.68	$2,308	2.82
238	T12 6' To Refrigerated Display Case Lighting 6' LED - Freezer CIP183	($1,873)	0.63	($454)	0.86	($1,354)	0.68	$1,846	2.82
239	T12 60” 1 Lamp To Delamp CIE151	$3,282	N/A	$393	1.11	$3,804	16.44	$3,651	10.14
240	T12 72” 1 Lamp To Delamp CIE152	$7,243	N/A	$903	1.11	$8,430	16.44	$8,121	10.51
241	T12 96” 1 Lamp To Delamp CIE153	$60,800	N/A	$8,362	1.12	$71,570	16.44	$69,651	11.63
242	T8 2 Lamp 4' To LED 1 Lamp Linear 4' CIE178	($5,043)	0.80	($1,837)	0.92	($524)	0.98	$14,434	3.38
243	T8 2L 4', 28W, CEE V CDI132	$16,306	1.18	($55,730)	0.56	($25,373)	0.74	($3,171)	0.96
244	T8 3 Lamp 4' To LED 2 Lamp Linear 4' CIE177	($2,105)	0.85	($1,588)	0.88	($1)	1.00	$8,063	2.97
245	T8 3L 4', 28W, CEE V CDI133	$6,935	1.33	($12,528)	0.64	($1,118)	0.95	$4,214	1.23
246	T8 4L 4', 28W, CEE V CDI134	$16,613	1.25	($40,353)	0.60	($11,630)	0.84	$4,946	1.09
247	T8 5' To Refrigerated Display Case Lighting 5' LED - Cooler CIP180	($790)	0.37	($75)	0.85	($619)	0.40	$256	2.64
248	T8 5' To Refrigerated Display Case Lighting 5' LED - Freezer CIP182	($790)	0.37	($75)	0.85	($619)	0.40	$256	2.64
249	T8 6L or T5HO 4L Replacing 400-999 W HID V CDI135	$418,460	2.96	($25,775)	0.97	$564,806	2.87	$618,086	3.48
250	T8 HO 96" 2 Lamp To LED Low Bay 85 W3 CIE117	($1,674)	0.93	($3,754)	0.84	($947)	0.95	$11,873	2.64
251	T8 To 21" Tubular Skylight/Light Tube CIP188	($513)	0.59	$7	1.01	($231)	0.78	$644	4.82
252	T8 U-Tube 2 Lamp 2' To LED U-Tube CIE176	($466)	0.68	($143)	0.87	($255)	0.79	$615	2.81
253	Typical Custom Measure - Lighting CUS103	$167,953	1.52	$16,810	1.02	$368,488	1.96	$605,926	5.11
254	Typical Custom Measure - Non-Lighting CUS104	$102,880	1.26	($88,493)	0.87	$134,708	1.29	$431,727	3.48
255	Vending Machine Occ Sensor - Refrigerated Glass Front Cooler CIE187	$1,682	2.08	($350)	0.90	$1,379	1.86	$2,260	4.11
256	Vending Machine Occ Sensor - Refrigerated Beverage CIE186	$7,920	2.70	($1,040)	0.92	$6,757	2.30	$9,401	4.69
257	Vending Miser V CDI136	$16,535	2.75	($10,318)	0.70	$8,774	1.56	$11,142	1.83
258	VFD CHW Pump 20-100hp - Hospital CIP129	$120,238	37.83	$12,528	1.08	$153,600	14.81	$154,962	16.88
259	VFD CHW Pump 20-100hp - Hotel CIP123	$121,367	38.17	$8,185	1.05	$150,572	14.44	$151,934	16.44
260	VFD CHW Pump 20-100hp - Large Office CIP135	$68,869	22.09	$9,241	1.10	$90,464	12.99	$91,826	15.85
261	VFD CHW Pump <20hp - Hospital	$28,808		$2,407		$36,345		$36,591	

		Participant Test		RIM Test		TRC Test		UCT Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR	NPV $	BCR
	CIE190		21.11		1.06		12.40		13.44
262	VFD CHW Pump <20hp - Hotel CIE195	$14,539	21.30	$682	1.04	$17,809	12.11	$17,932	13.11
263	VFD CHW Pump <20hp - Large Office CIE200	$16,479	12.50	$1,618	1.07	$21,192	10.09	$21,438	11.29
264	VFD Compressor CIE203	$7,653	2.26	($346)	0.98	$10,538	2.86	$13,879	6.97
265	VFD CW Pump 20-100hp - Hospital CIP131	$34,533	11.58	$5,744	1.12	$47,071	10.07	$49,083	16.45
266	VFD CW Pump 20-100hp - Hotel CIP125	($1,330)	0.59	$283	1.13	($173)	0.94	$1,839	3.66
267	VFD CW Pump 20-100hp - Large Office CIP137	$16,492	6.05	$3,448	1.14	$23,755	7.03	$25,767	14.37
268	VFD CW Pump <20hp - Hospital CIE192	$3,405	6.43	$540	1.11	$4,715	7.11	$5,091	13.84
269	VFD CW Pump <20hp - Hotel CIE197	($155)	0.42	($14)	0.89	($105)	0.52	$56	1.96
270	VFD CW Pump <20hp - Large Office CIE202	$1,511	3.41	$299	1.11	$2,267	4.54	$2,643	10.96
271	VFD HW Pump 20-100hp - Hospital CIP130	$101,456	32.07	$15,040	1.12	$134,271	14.66	$135,883	17.53
272	VFD HW Pump 20-100hp - Hotel CIP124	$128,158	40.25	$11,016	1.07	$161,357	14.80	$162,969	17.17
273	VFD HW Pump 20-100hp - Large Office CIP136	$67,034	21.53	$19,781	1.23	$98,908	14.30	$100,520	18.26
274	VFD HW Pump <20hp - Hospital CIE191	$10,579	17.88	$1,369	1.10	$13,871	12.01	$14,058	14.10
275	VFD HW Pump <20hp - Hotel CIE196	$5,735	22.35	$406	1.05	$7,164	12.49	$7,244	14.33
276	VFD HW Pump <20hp - Large Office CIE201	$6,965	12.11	$1,867	1.20	$10,158	11.08	$10,345	13.59
277	VFD Return Fan 20-100hp - Hospital CIP127	$31,961	10.79	$4,648	1.11	$42,994	9.55	$45,106	16.46
278	VFD Return Fan 20-100hp - Hotel CIP121	($34)	0.99	$113	1.03	$1,184	1.42	$3,296	5.78
279	VFD Return Fan 20-100hp - Large Office CIP133	$22,492	7.89	$4,703	1.15	$32,017	8.33	$34,129	16.12
280	VFD Return Fan <20hp - Hospital CIE188	$7,189	6.02	$947	1.09	$9,799	6.68	$10,657	13.28
281	VFD Return Fan <20hp - Hotel CIE193	($245)	0.66	($70)	0.87	($118)	0.80	$311	2.87
282	VFD Return Fan <20hp - Large Office CIE198	$4,917	4.43	$961	1.12	$7,165	5.57	$8,023	12.30
283	VFD Supply Fan <100hp - Hospital CIP132	$37,387	12.45	$5,784	1.12	$50,452	10.33	$52,564	16.95
284	VFD Supply Fan <100hp - Hotel CIP126	($1,691)	0.48	($451)	0.75	($1,312)	0.51	$800	2.39
285	VFD Supply Fan <100hp - Large Office CIP138	$29,684	10.09	$5,903	1.15	$41,597	9.54	$43,709	16.85
286	VFD Tower Fan 20-100hp - Hospital CIP128	$12,755	4.91	$9,977	1.51	$25,967	8.03	$28,204	20.33
287	VFD Tower Fan 20-100hp - Hotel CIP122	$18,620	6.70	$13,857	1.51	$36,682	9.94	$38,919	21.86
288	VFD Tower Fan 20-100hp - Large Office CIP134	($1,762)	0.46	$371	1.21	($552)	0.79	$1,685	4.72
289	VFD Tower Fan <20hp - Hospital CIE189	$2,538	2.77	$2,268	1.47	$5,713	5.06	$6,643	14.95
290	VFD Tower Fan <20hp - Hotel CIE194	$3,946	3.75	$3,200	1.49	$8,284	6.51	$9,214	17.06
291	VFD Tower Fan <20hp - Large Office CIE199	($946)	0.34	($37)	0.93	($652)	0.44	$279	2.19
292	Water Heater Pipe Insulation - 6' CDI139	$286,572	N/A	($43,293)	0.92	$374,055	4.44	$374,055	4.44
293	Water Heater Setback (manual adj) CDI140	$50,942	N/A	($52,784)	0.51	($122)	1.00	($122)	1.00
294	Window Film CIP139	$14	1.21	($9)	0.89	$20	1.35	$47	2.50

2015 ELECTRIC DSM PLAN – CAUSE NO. 44495

Energy efficiency measures considered for the programs were developed using existing Indiana utility program measures (whenever possible) and measures used in other programs in the region. It should be noted that in any plan measures within programs will change and adapt to changing technology and markets. The 2015 Plan shows a framework of measures and programs that can meet the savings goals; however, it is expected that new measures and opportunities will become available during this period and that some measures will phase out as standards change and they are no longer cost effective.

The technologies listed above were developed as a result of the EnerNOC MPS data and other study information in order to guide the plan design. Vectren then hired outside expertise to assist with plan design and development in order to refine the technologies above into a workable plan. Additionally, input into the plan design was obtained from various sources, such as current program managers and implementation partners, in order to establish a solid foundation for the 2015 Plan that is based on actual experience in Vectren's territory. Other program information, such as current evaluations and best practices of other successful DSM programs, was used for adjustments to inputs. Lastly, Vectren received feedback and approval from the Oversight Board before finalizing. The result of these efforts, listed in Table 8-4 below, shows the DSM Programs benefit/cost data per the portfolio of programs filed under Cause No. 44495.

Table 8-4 Program Benefit/Cost Results for 2015 DSM Plan[1]

Commercial	TRC	UCT	RIM	Participant
Small Business Direct Install	2.00	2.21	0.83	3.66
Commercial & Industrial Prescriptive	3.75	5.44	1.02	3.25
Commercial & Industrial New Construction	1.09	2.72	0.87	1.00
Commercial & Industrial Custom	1.64	3.82	0.93	1.52
Commercial Sector Portfolio	**2.17**	**3.08**	**0.90**	**2.63**

Residential	TRC	UCT	RIM	Participant
Residential Lighting	2.18	2.88	0.85	2.94
Home Energy Assessments	1.02	1.02	0.56	NA
Income Qualified Weatherization	1.14	1.14	0.66	NA
Appliance Recycling	2.52	2.51	0.97	5.79
Residential Schools	1.89	1.89	0.72	NA
Efficient Products	1.51	2.02	1.05	1.13
Residential New Construction	1.28	1.52	0.75	1.89
Residential Behavior Savings	1.64	1.64	0.77	NA
Residential Sector Portfolio	**1.49**	**1.64**	**0.77**	**3.36**

Total Portfolio	**1.86**	**2.34**	**0.85**	**2.89**

Table 8-4 Program Benefit/Cost Results for 2015 DSM Plan Cont.[2]

Commercial	Lifetime Cost/ kWh	1st Year Cost/ kWh
Small Business Direct Install	$0.04	$0.32
Commercial & Industrial Prescriptive	$0.01	$0.15
Commercial & Industrial New Construction	$0.03	$0.36
Commercial & Industrial Custom	$0.02	$0.23
Commercial Sector Portfolio	**$0.03**	**$0.26**

[1] Commercial sector includes outreach costs for benefit/cost runs, and residential sector includes outreach and tracking costs for benefit/cost runs

[2] Commercial sector includes outreach costs for benefit/cost runs, and residential sector includes outreach and tracking costs for benefit/cost runs

Residential	Lifetime Cost/kWh	1st Year Cost/kWh
Residential Lighting	$0.03	$0.07
Home Energy Assessments	$0.08	$0.35
Income Qualified Weatherization	$0.07	$0.78
Appliance Recycling	$0.04	$0.16
Residential Schools	$0.04	$0.23
Efficient Products	$0.06	$0.67
Residential New Construction	$0.04	$0.92
Residential Behavior Savings	$0.06	$0.07
Residential Sector Portfolio	**$0.05**	**$0.18**
Total Portfolio	**$0.03**	**$0.21**

Commercial	TRC NPV $	UCT NPV $	Participant NPV $	RIM NPV $
Small Business Direct Install	$2,116,270	$2,319,485	$2,311,703	($888,566)
Commercial & Industrial Prescriptive	$3,072,637	$3,419,025	$2,406,007	$76,945
Commercial & Industrial New Construction	$40,071	$305,069	($32)	($71,053)
Commercial & Industrial Custom	$726,468	$1,376,727	($26,798)	$695,808
Commercial Sector Portfolio	**$5,805,446**	**$7,270,305**	**$5,193,787**	**($1,181,366)**

Residential	TRC NPV $	UCT NPV $	Participant NPV $	RIM NPV $
Residential Lighting	$929,179	$1,121,826	$1,838,832	($307,982)
Home Energy Assessments	$15,690	$15,690	$572,651	($572,019)
Income Qualified Weatherization	$115,688	$115,688	$416,861	($468,781)
Appliance Recycling	$320,800	$319,656	$470,616	($15,444)
Residential Schools	$113,569	$113,569	$182,611	($94,479)
Efficient Products	$352,915	$524,039	$82,526	$53,200
Residential New Construction	$39,816	$61,965	$50,858	($61,654)
Residential Behavior Savings	$274,885	$274,885	$487,718	($212,832)
Residential Sector Portfolio	**$1,992,542**	**$2,377,317**	**$4,102,673**	**($1,849,991)**
Total Portfolio	**$7,797,988**	**$9,647,622**	**$9,296,460**	**($3,031,357)**

The following programs were filed in the 2015 Plan in Cause No. 44495.

School Energy Efficiency Program

Program

The Energy Efficient Schools Program is designed to impact students by teaching them how to conserve energy and to produce cost effective electric savings by influencing students and their families to focus on conservation and the efficient use of electricity.

The program consists of a school education program for 5th grade students attending schools served by Vectren. To help in this effort, each child that participates will receive a take-home energy kit with various energy saving measures for their parents to install in the home. The kits, along with the in-school teaching materials, are designed to make a lasting impression on the students and help them learn ways to conserve energy.

Eligible Customers

The program will be available to selected 5th grade students/schools in the Vectren electric service territory.

Energy/Demand Savings

The proposed savings are attributed to the take-home kits provided to the elementary school children for parents to install. For modeling purposes, the energy savings estimate is 216 kWh per participant and .020 kW.

Table 8-5 School Energy Efficiency Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential Schools				
	2015	2,600	560,786	52	$ 128,033
Per Participant Avg Energy Savings (kWh)					216
Per Participant Avg Demand Savings (kW)					0.020
Participant Incremental Cost					$ -
Weighted Avg Measure Life					7
Net To Gross Ratio					96%

Residential Lighting Program

Program

The Residential Lighting Program is a market-based residential DSM program designed to reach residential customers through retail outlets. The program design consists of a buy-down strategy to provide the incentive to consumers to facilitate their purchase of energy-efficient lighting products. This program is justified based on direct energy savings targets, but also has a significant market transformation opportunity.

The program not only empowers customers to take advantage of new lighting technologies and accelerate the adoption of proven energy efficient technologies, but also allows the customers to experience the benefits of energy efficiency and decrease their energy consumption.

Eligible Customers

Any residential customer who receives electric service from Vectren is eligible.

Energy/Demand Savings

The program is designed to provide an incentive for the purchase and installation of CFL bulbs. For modeling purposes, the savings estimates per bulb are 32 kWh annually with demand savings of 0.004 kW.

Table 8-6 Residential Lighting Program Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential Lighting				
	2015	261,316	8,334,008	978	$ 596,567
Per Participant Avg Energy Savings (kWh)					32
Per Participant Avg Demand Savings (kW)					0.004
Participant Incremental Cost					$ 3.63
Weighted Avg Measure Life					6
Net To Gross Ratio					49%

Home Energy Assessments

Program

The Home Energy Assessment Program targets a hybrid approach that combines helping customers analyze and understand their energy use via an on-site energy assessment, as well as providing direct installation of energy efficiency measures including efficient low-flow water fixtures and CFL bulbs.

Collaboration and coordination between electric and gas conservation programs will be explored and, to the extent possible, implemented for greatest efficiencies.

Eligible Customers

Any residential customer who receives electric service from Vectren at a single-family residence is eligible, provided the home:

- Was built prior to 1/1/2010;
- Has not had an audit within the last three years; and,
- Is owner occupied or non-owner occupied where occupants have the electric service in their name.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,036 kWh and .164 kW per participant.

Table 8-7 Home Energy Assessments Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Home Energy Assessments				
	2015	2,000	2,072,900	328	$ 716,163
Per Participant Avg Energy Savings (kWh)					1,036
Per Participant Avg Demand Savings (kW)					0.164
Participant Incremental Cost					$ -
Weighted Avg Measure Life					6
Net To Gross Ratio					88%

Income Qualified Weatherization

Program

The Low Income Weatherization program is designed to produce long-term energy and demand savings in the residential market. The program will provide weatherization upgrades to low income homes that otherwise would not have been able to afford the energy saving measures. The program will provide direct installation of energy saving measures, educate consumers on ways to reduce energy consumption, and identify opportunities for additional weatherization measures.

Collaboration and coordination between gas and electric low income programs along with state and federal funding, is recommended to provide the greatest efficiencies among all programs.

Eligible Customers

The Residential Low Income Weatherization Program targets single-family homeowners and tenants, who have electric service in their name with Vectren and with a total household income up to 200% of the federally-established poverty level. Priority will be given to:

a. Single parent households with children under 18 years of age living in dwelling.
b. Households headed by occupants over 65 years of age.
c. Disabled homeowners as defined by the Energy Assistance Program (EAP).
d. Households with high energy intensity usage levels.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,822 kWh per participant annually with demand savings of 0.453 kW.

Table 8-8 Income Qualified Weatherization Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Income Qualified Weatherization				
	2015	564	1,027,651	256	$ 798,474
Per Participant Avg Energy Savings (kWh)					1,822
Per Participant Avg Demand Savings (kW)					0.453
Participant Incremental Cost					$ -
Weighted Avg Measure Life					15
Net To Gross Ratio					100%

Appliance Recycling

Program

The Residential Appliance Recycling program encourages customers to recycle their old inefficient refrigerators and freezers in an environmentally safe manner. The program recycles operable refrigerators or freezers so the appliance no longer uses electricity and is recycled instead of being disposed of in a landfill. An older refrigerator can use as much as twice the amount of energy as new efficient refrigerators. An incentive of $50 will be provided to the customer for each operational unit picked up.

Eligible Customers

Any residential customer with an operable secondary refrigerator or freezer receiving electric service from Vectren is eligible.

Incentive

The program offers customers free pick-up of working refrigerators or freezers and a $50 cash incentive.

Energy/Demand Savings

The program is designed to remove the old, secondary refrigerator or freezer. The savings estimate is 1,230 kWh per measure annually, with a summer demand savings of 0.397 kW.

Table 8-9 Residential Appliance Recycling Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Appliance Recycling				
	2015	1,058	1,301,338	420	$ 212,366
Per Participant Avg Energy Savings (kWh)					1,230
Per Participant Avg Demand Savings (kW)					0.397
Participant Incremental Cost					$ 92 96
Weighted Avg Measure Life					8
Net To Gross Ratio					53%

Residential Efficient Products

Program

To assist customers with the purchase of energy efficient products, prescriptive incentives will be provided on efficient electric measures and equipment (qualifying air conditioning units, heat pumps, thermostats, etc.) above the standard baseline. The program will be promoted through trade allies and appropriate retail outlets.

Eligible Customers

Any residential customer located in the Vectren electric service territory is eligible.

Incentive

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option.

Energy/Demand Savings

For modeling purposes, the energy/demand savings estimates are 514 kWh annually per participant (measure) and demand savings of .403 kW.

Table 8-10 Residential Efficient Products Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Efficient Products				
	2015	1,500	771,461	605	$ 516,189
Per Participant Avg Energy Savings (kWh)					514
Per Participant Avg Demand Savings (kW)					0.403
Participant Incremental Cost					$ 421 53
Weighted Avg Measure Life					15
Net To Gross Ratio					73%

Residential Behavioral Savings Program

Program

The Residential Behavioral Savings (RBS) program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact via mailed and emailed home energy reports. The report and web portal include a comparison against a group of similarly sized and equipped homes in the area, usage history comparisons, goal setting tools, and progress trackers. The Home Energy Report program anonymously compares customers' energy use with that of their neighbors of similar home size and demographics. Customers can view the past twelve months of their energy usage and compare and contrast their energy consumption/ costs with others in the same neighborhood. Once a consumer better understands how they use energy, they can then start conserving energy.

Program data and design was provided by OPower, the implementation vendor for the program. OPower provides energy usage insight that drives customers to take action

by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

Eligible Customers

Residential customers who receive electric service from Vectren are eligible.

Energy/Demand Savings

To identify the measurable savings, Vectren proposes to have a set of customers who receive the letter with energy tips and suggestions and a set of control customers who do not receive the letter. The energy consumption of the 2 groups will be compared to determine the measurable savings. For modeling purposes, the annual energy savings was estimated at 126 kWh per participant with demand savings of .041 kW.

Table 8-11 Residential Behavioral Savings Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Behavioral Savings				
	2015	50,400	6,350,400	2,051	$ 432,202
Per Participant Avg Energy Savings (kWh)					126
Per Participant Avg Demand Savings (kW)					0.041
Participant Incremental Cost					$ -
Weighted Avg Measure Life					1
Net To Gross Ratio					100%

Residential New Construction

Program

The Residential New Construction Program will provide incentives and encourage home builders to construct homes that are more efficient than current building codes. The Residential New Construction Program will work closely with builders, educating them on the benefits of energy efficient new homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be

more efficient and comfortable than standard homes constructed to current building codes.

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site.

The Residential New Construction Program will address the lost opportunities in this customer segment by promoting energy efficiency at the time the initial decisions are being made. This will ensure efficient results for the life of the home.

Eligible Customers

Any home builder constructing a home to the program specifications in the Vectren electric service territory is eligible.

Incentives

Incentives will be based on a rating tier qualification and are designed to be paid to both all-electric and combination homes that have natural gas space heating.

Energy/ Demand Savings

For modeling purposes, the savings estimates per home are calculated at 1,898 kWh and .309 kW, based upon the blended savings estimate of all participating homes. The specific energy and demand impacts will vary by size and composition of the home and will be characterized through follow-up evaluation and verification procedures.

Table 8-12 Residential New Construction Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Residential	Residential New Construction				
	2015	68	129,048	21	$ 119,092
Per Participant Avg Energy Savings (kWh)					1,898
Per Participant Avg Demand Savings (kW)					0.309
Participant Incremental Cost					$ 844 56
Weighted Avg Measure Life					25
Net To Gross Ratio					95%

Commercial and Industrial Prescriptive Program

Program

The Commercial and Industrial (C&I) Prescriptive Program is designed to provide financial incentives on qualifying products to produce greater energy savings in the C&I market. The rebates are designed to promote lower electric energy consumption, assist customers in managing their energy costs and built a sustainable market around energy efficiency. Program participation is achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

Incentives are provided to customers to reduce the difference in first cost between the lower efficient technology and the high efficient option.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 487 kWh per participant (measure) and demand savings of .089 kW.

Table 8-13 Commercial and Industrial Prescriptive Program Data

Market	Program	Number of Measures	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial Prescriptive				
	2015	10,470	5,103,942	935	$ 769,573
Per Participant Avg Energy Savings (kWh)					487
Per Participant Avg Demand Savings (kW)					0.089
Participant Incremental Cost					$ 102 29
Weighted Avg Measure Life					14
Net To Gross Ratio					80%

Commercial and Industrial Audit and Custom Efficiency Program

Program

The Commercial and Industrial Custom Program promote the implementation of customized energy saving measures at qualifying customer facilities. Incentives promoted through this program serve to reduce the cost of implementing energy reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom energy efficiency program, a wide variety of projects are eligible.

The technical audit or compressed air system study offers an assessment to systematically identify energy saving opportunities for customers and provides a mechanism to prioritize and phase-in projects that best meet customer needs. In turn, the opportunities identified from the audit can be turned in for the customized efficiency program. These two components work hand in hand to deliver energy savings to Vectren commercial and industrial customers.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

Vectren will provide a customer incentive based on the estimated kWh savings at a modeled rate of .12 cents per kWh, and is paid based on the first year annual savings reduction.

Energy/Demand Savings

The custom nature of the program makes it difficult to develop a prototypical example. Each building will have very site specific projects and impacts. For modeling purposes the energy/demand savings estimates are 95,248 kWh per participant (measure) and demand savings of 15.455 kW.

Table 8-14 Commercial and Industrial Audit & Custom Efficiency Program Data

Market	Program	Number of Projects	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial Custom				
	2015	22	2,095,450	340	$ 488,274
Per Participant Avg Energy Savings (kWh)					95,248
Per Participant Avg Demand Savings (kW)					15.455
Participant Incremental Cost					$ 41,400.96
Weighted Avg Measure Life					12
Net To Gross Ratio					99%

Commercial and Industrial New Construction Program

Program

The Commercial and Industrial New Construction Program provides value by promoting energy efficient designs with the goal of developing projects that are more energy efficient than current Indiana building code. Incentives promoted through this program serve to reduce the incremental cost to upgrade to high-efficiency equipment over standard efficiency options for Vectren customers. The program includes equipment with easily calculated savings and provides straightforward and easy participation for customers.

Eligible Customers

Any participating commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

The program is designed to pay .12 cents per kWh saved up to $100,000 based on the first year energy savings determined in the final energy model.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings per participant are 35,100 kWh and 6.286 kW.

Table 8-15 Commercial and Industrial New Construction Program Data

Market	Program	Number of Participants	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial & Industrial	Commercial & Industrial New Construction				
	2015	14	491,400	88	$ 177,373
Per Participant Avg Energy Savings (kWh)					35,100
Per Participant Avg Demand Savings (kW)					6.286
Participant Incremental Cost					$ 24,517 34
Weighted Avg Measure Life					14
Net To Gross Ratio					95%

Small Business Direct Install

Program

The program provides value by directly installing energy efficient products such as high efficiency lighting, low flow water saving measures and vending machine controls. The program helps businesses identify and install cost effective energy saving measures by providing an on-site energy assessment customized for their business.

Eligible Customers

Any participating Vectren small business customer with a maximum peak energy demand of less than 300 kW is eligible.

Incentive

In addition to the low cost measures installed during the audit, the program will also pay a cash incentive of up to 75% of the cost of any recommended improvements identified through the audit.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings per participant are 6,001 kWh and 1.622 kW.

Table 8-16 Small Business Direct Install Program Data

Market	Program	Number of Projects	Energy Savings kWh	Peak Demand kW	Total Program Budget $
Commercial	Small Business Direct Install				
	2015	1,000	6,001,171	1,622	$ 1,909,188
Per Participant Avg Energy Savings (kWh)					6,001
Per Participant Avg Demand Savings (kW)					1.622
Participant Incremental Cost					$ 868.98
Weighted Avg Measure Life					10
Net To Gross Ratio					100%

DSM Portfolio Objective and Impacts

Vectren plans to reduce residential and commercial/industrial customer usage by 34,240 MWh in 2015. Vectren also projects to achieve a reduction in summer peak demand of 7.69 MW in 2015. In implementing these programs, consideration will be given to utilizing small businesses when feasible. Table 8-17 outlines the portfolio and the associated programs, as well as the projected energy/demand impacts, program costs, and customer participation of DSM programs offered under Cause No. 44495.

Table 8-17 Projected Energy and Peak Savings – Cause No. 44495

COMMERCIAL	2015 kWh Total	2015 kW
Small Business Direct Install	6,001,171	1,622
Commercial & Industrial Prescriptive	5,103,942	935
Commercial & Industrial New Construction	491,400	88
Commercial & Industrial Custom	2,095,450	340
Commercial Total	**13,691,963**	**2,985**

RESIDENTIAL	2015 kWh Total	2015 kW
Residential Lighting	8,334,008	978
Home Energy Assessments	2,072,900	328
Income Qualified Weatherization	1,027,651	256
Appliance Recycling	1,301,338	420
Residential Schools	560,786	52
Efficient Products	771,461	605
Residential New Construction	129,048	21
Behavior Savings	6,350,400	2,051
Residential Total	**20,547,593**	**4,711**

While Vectren believes this level of savings is achievable, it will require robust programs for all classes of retail customers.

Given the market assessment, collaborative process, portfolio cost/benefit modeling efforts, and DSM program portfolio proposal, Vectren used the projected demand-side reductions from the programs as an input into the IRP process, rather than allowing the integration modeling to independently select some level of DSM to meet customer requirements. With respect to DSM, the programs that pass cost effectiveness testing are input into the integration analysis as a resource. IRP DSM modeling is discussed later in this chapter.

Customer Outreach and Education

Program

This program will raise awareness and drive customer participation as well as educate customers on how to manage their energy bills. The program will include the following goals as objectives:

- Build awareness;
- Educate consumers on how to conserve energy and reduce demand;
- Educate customers on how to manage their energy costs and reduce their bill;
- Communicate Vectren's support of customer energy efficiency needs; and
- Drive participation in the DSM programs.

This annual program will include paid media, web-based tools to analyze bills, energy audit tools, and energy efficiency and DSM program education and information. Informational guides and sales promotion materials for specific programs will also be included.

Vectren will oversee the outreach and education programs for the DSM programs. Vectren will utilize the services of communication and energy efficiency experts to deliver the demand and energy efficiency message.

Eligible Customers

Any Vectren electric customer will be eligible.

Energy/Demand Savings

This communications effort differs from typical DSM programs in that there are no direct estimates of participants, savings, costs, and cost-effectiveness tests. Such estimates are considered impractical for these types of overarching efforts to educate consumers and drive participation in other DSM programs. The California Standard Practice Manual (p. 5) addresses this issue as follows:

"For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts."

This effort is the key to achieving greater energy savings by convincing the families and businesses making housing/facility, appliance and equipment investments to opt for greater energy efficiency. The first step in convincing the public and businesses to invest in energy efficiency is to raise their awareness. It is essential that a broad public education and outreach campaign not only raise awareness of what consumers can do to save energy and control their energy bills, but to prime them for participation in the various DSM programs. The budget is $150,000 each for Residential and Commercial programs, for a total of $300,000.

Table 8-18 DSM Outreach & Education Program Budget

Customer Outreach	Residential	Business	Total Program Costs
Outreach	$150,000	$150,000	$300,000

IRP DSM MODELING

Vectren continues to support DSM related energy efficiency efforts as a fundamental part of the services that are provided to customers in order to help them manage their energy bills. The Market Potential study, developed by EnerNoc on behalf of the Vectren Oversight Board, illustrated a level of ongoing DSM energy efficiency is cost effective and Vectren believes the inclusion of the described level of ongoing DSM energy efficiency is best reflected in the base case sales forecast. DSM energy efficiency programs included in the base sales forecast are available to all customer classes at a targeted level of 1% eligible annual savings for 2015 – 2019 and 0.5%

annually thereafter for customer load that has not opted-out of DSM programs. Vectren believes that a cost effective level of DSM energy efficiency may be supported by policy considerations beyond capacity planning which are not always captured in the IRP modeling process.

Vectren did model the option of offering DSM energy efficiency programs designed to achieve more than the level reflected in the base case sales forecast to determine if it is selected as a resource to meet future electric requirements. Vectren's approach attempts to balance its commitment to a level of cost-effective DSM, while evaluating additional DSM resources consistent with least cost planning. Below is a list of major assumptions included in Vectren's IRP DSM modeling.

Vectren began by creating savings blocks based on 0.5% of eligible sales based on a projection that 80% of large customers will opt out of Vectren sponsored DSM programs. The maximum amount of possible additional DSM that could be selected was 2% (embedded savings + additional modeled blocks) in 2018-2019. Beyond 2019, the model was limited to selecting 1.5% (embedded + additional modeled blocks) of total eligible sales, consistent with the proposed Clean Power Plan (111d). Levelized costs were based on the Market Potential study and Vectren's 2015 Plan. Consistent with the Market Potential study, each block cost more than the last and increased over time. Levelized costs of energy saved began at approximately 3 cents per kWh for the first available block in 2015 and increased to approximately 6.4 cents for the last available block in 2034. In order to minimize ramping costs, DSM programs were required to run for at least 3 consecutive years.

Based on these assumptions, DSM successfully competed with resource alternatives within the planning model to help meet future load requirements. DSM was selected in several resource plans as discussed further in Chapter 10 Generation Planning.

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CHAPTER 9

TRANSMISSION AND DISTRIBUTION PLANNING

INTRODUCTION

In accordance with IURC Rule 170 IAC, Vectren analyzed its transmission and distribution system's ability to meet future electric service requirements reliably and economically through the year 2034. This chapter describes the criteria applied in the analysis and the system conditions studied. The study was conducted to maintain compliance with the requirements of the Midcontinent Independent System Operator (MISO), the *Reliability* First (RF) in conjunction with NERC requirements, as well as Vectren's internal planning criteria. Internal Long Range Plans are completed annually. In addition, Vectren has worked closely with MISO Transmission Expansion Plans (MTEP) and RF in performing regional studies, which include proposed projects identified in Vectren studies.

Modeling of the transmission system was conducted with steady-state conditions using the Power Technologies Inc.'s Power System Simulator Program for Engineers (PTI-PSS/E). The models and the studies and assessment on these models comply with all NERC, RF, MISO and IURC requirements, and they include real and reactive flows, voltages, generation dispatch, load, and facilities appropriate for the time period studied. The primary criteria for assessing the adequacy of the internal Vectren transmission system were (1) single contingency outages of transmission lines and transformers during peak conditions, and (2) selected double and multiple contingencies. Interconnections were also assessed by examining single, double, and other multiple contingencies.

In addition, short circuit models were developed and analyzed through the use of Advanced Systems for Power Engineering, Inc.'s short circuit program (ASPEN-OneLiner).

Dynamic simulation was also performed using PTI-PSS/E to examine the performance of the interconnected transmission system to various electrical faults. The Vectren system remains stable for a variety of faulted conditions.

METHODOLOGY

The distribution system review covers native load as described in previous chapters in this IRP. The Transmission system review also covers loads connected to Vectren's transmission system such as municipals and Independent Power Producers (IPP's) that Vectren is not obligated to serve or include in its generation resources. The primary reason is to determine impacts or limitations in the transmission capacity to serve the Vectren native load. Vectren adheres to the transmission planning criteria developed and published by MISO in its document MISO *Transmission Expansion Planning*; (MTEP) and by RF through NERC in its *Reliability Standards* under *Transmission Planning (TPL-001 through TPL-004)*.

The basis for the selection of RF reliability criteria offers five points for member recognition.

1. The need to plan bulk electric systems that will withstand adverse credible disturbances without experiencing uncontrolled interruptions.

2. The importance of providing a high degree of reliability for local power supply but the impossibility of providing 100 percent reliability to every customer or every local area.

3. The importance of considering local conditions and requirements in establishing transmission reliability criteria for the local area power supply and the need, therefore, to view reliability in local areas primarily as the responsibility of the individual RFC members. However, local area

disturbances must not jeopardize the overall integrity of the Bulk Electric System.

4. The importance of mitigating the frequency, duration and extent of major Bulk Electric System outages.

5. The importance of mitigating the effect of conditions that might result from events such as national emergencies, strikes, or major outages on other regional networks.

SYSTEM INTEGRITY ANALYSIS – 2013 (SEASONAL ANNUAL, INCLUDES SPRING, SUMMER, FALL, AND WINTER)

Based on initial conditions for load, generation, and system topology the following tests were conducted.

1. Single contingency:
   - Outage of any line
   - Outage of any transformer
   - Outage of any generator
2. Multiple contingencies:
   - Double outage of any combination of generators, lines and transformers
   - Double outages of generators
   - Sensitivity outages: two lines or transformers under different Generation dispatch scenarios
3. Extreme Contingencies:
   - Loss of all generation at a plant site
   - Loss of entire switchyard with associated load, generation and line connectivity where three or more 100kV or higher voltage lines are connected

As a result of these tests, various system operational or construction improvements have been postulated. These improvements may be either operator action, (such as shifting generation or switching lines), or the installation of actual substations, the construction of transmission lines, or the upgrading of facilities. Required construction improvements have been prioritized by where they fall in the contingency spectrum. Improvements that must be made in response to a single line outage have higher priority than improvements resulting from a more unlikely occurrence.

SYSTEM INTEGRITY ANALYSIS – 2018 (NEAR TERM – WITHIN 1-5 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2013 system. Contingency analysis is also the same as for the 2013 system.

SYSTEM INTEGRITY ANALYSIS – 2022 (LONG TERM – 6-10 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2013 system. Contingency analysis is the same as for the 2013 system.

TRANSMISSION ADEQUACY SUMMARY TABLE

Table 9-1 shows the Vectren generation and load resources, as summarized from previous chapters, as well as the generation and load resources expected to be served from the transmission system for the entire Vectren Local Balancing Authority (LBA) as coordinated by MISO.

Table 9-1 Transmission Import Adequacy/Shortfall Assessment

Year	Vectren Available Gen (MW)[1]	IPP's & other Gen (MW)	Vectren Firm Peak Demand (MW)[2]	Muni's & Other Load (MW)	Proj. Inter-Change (MW)	Trans. System Import Cap (MW)
2014	1,155	596	1,145	690	-84	728
2015	1,155	680	1,155	690	-10	802
2016	1,155	680	1,156	690	-11	801
2017	1,155	680	1,113	690	32	844
2018	1,155	680	1,109	690	36	848
2019	1,155	680	1,106	690	39	851
2020	1,155	680	1,106	690	39	851
2021	1,155	680	1,106	690	39	851
2022	1,155	680	1,107	690	38	850
2023	1,155	680	1,107	690	38	850
2024	1,155	680	1,107	690	38	850
2025	1,155	680	1,106	690	39	851
2026	1,155	680	1,106	690	39	851
2027	1,155	680	1,107	690	38	850
2028	1,155	680	1,109	690	36	848
2029	1,155	680	1,110	690	35	847
2030	1,155	680	1,111	690	34	846
2031	1,155	680	1,111	690	34	846
2032	1,155	680	1,113	690	32	844
2033	1,155	680	1,114	690	31	843
2034	1,155	680	1,115	690	30	842

The table reflects that if all available internal generation is on line the expected net interchange would be negative for years 2014 through 2016 and positive or exporting for all years beyond 2017. This reliability measure indicates that additional import transmission capacity is not needed for our generation to serve our load. However, the table does not reflect several other factors such as potential purchases and sales. The

[1] Values from Table 10-1 Characteristics of Existing Generation Resources
[2] Values from Table 5-4 Base Case Demand Forecast

table reflects total generation capability and not a reasonable economic dispatch under all conditions. It is likely that renewable energy resources may be imported using the transmission system in lieu of running local generation. It is assumed that the gas peaking turbines would likely not be dispatched during some near peak summer conditions, in which it is not only possible, but likely that the expected interchange could be importing 300-400 MW. These values are also supported by actual historical interchange. In any event, MISO will dispatch the available resources to serve the load based on N-1 contingency analysis and economics and losses. With the largest generation resource on the Vectren system at 300 MW, the transmission system capacity is adequate under reasonable expected resource dispatches and contingencies and additional growth. Within each PSS/E case, the actual load, generation dispatch, firm purchases and sales, and expected interchange is appropriate for the time period.

RECOMMENDATIONS: 2014 - 2034

No transmission facilities were identified specifically due to proposed generation interconnections, transmission service requests or energy resources in this IRP process. Since the projected load growth is essentially flat and no new generation resources or retirements are planned, no new transmission facilities have been identified. In addition, significant upgrades were constructed in 2012 as a result of the MISO Regional Expansion Criteria and Benefits (RECB) process. The completed projects include the construction of a new 345 kV line from the Duke Gibson Station to the Vectren AB Brown Station to the BREC Reid Station. The Duke Gibson to Vectren AB Brown to BREC Reid EHV Substation is complete and energized. This project also included the construction of a 345/138 kV substation at Vectren's AB Brown Station which is also complete. A new 138kV line (Z77) from FB Culley Substation to Oak Grove Substation to Northeast Substation is complete. This facility allows for better generation dispatch diversity with lower congestion costs under contingencies. However, recent generation and load changes in the Commonwealth of Kentucky are

expected to impact the Vectren system due to flow through congestion. MISO is considering Market Congestion Projects for mitigation of the projected congestion costs, and a project will only move forward if the benefits exceed the costs metric. Multiple distribution substation upgrades were completed to include Bergdolt and Libbert Substations. Leonard Rd 69kV Switching substation should be complete in 2014 and will support a greater number of contingencies for substransmission on Evansville's west side. Demand side management and energy conservation is expected to provide some load reduction on the Vectren system.

Local load growth areas have been identified for potential new business loads. Near term projections indicate the need for at least 2 more distribution substations tentatively identified as Roesner Road and Princeton South areas, as well as potentially a new plant.

The specific projects to be completed in the future years will depend on the load growth, the location of generation facilities, and/or on the source of purchased power. General recommendations are as follows:

1. A number of 69 kV transmission upgrades will be needed. An engineering evaluation will be conducted for upgrading the identified lines to higher operating temperature and for reconductoring some lines.
2. A number of substations will need to be modified.
3. Several new 138 and 69 kV lines and substations are planned to be added in this timeframe.
4. New high voltage interconnections with neighboring utilities are being investigated, including 345 kV facilities, to improve import capability and improve regional reliability.
5. If new generation capacity is added within the Vectren system, transmission facilities would also be planned to incorporate the new power source.

6. If new generation capacity were acquired outside the Vectren system, additional new interconnections may be needed. These projects would be investigated and would require involvement of other utilities.

All of these potential transmission projects would be planned with and coordinated through the MISO.

COST PROJECTIONS:

Vectren is projecting its annual transmission, substation, and distribution expenditures to remain flat to slightly decrease over the next five years. The primary factors are that there is not a recommendation to add new generation sources in this IRP that causes new construction and the existing transmission system is adequate for full deliverability of the existing generation sources. A reason for part of the decrease is the 345kV project was completed in 2012 and spending in following years are expected to be lower. However, the Federal Stimulus Plan funding is expected to force some transmission and distribution relocations increasing in some areas due to roadway improvements. Approximately half of these are expected to be reimbursable with the remaining cost incurred by Vectren. Also, increasing demands for Smart Grid technology and infrastructure are resulting in some additional expenditure. New business and load growth forecast is expected to stay relatively flat. The need for import capability due to generation additions and retirements are expected to remain mostly unchanged as well. Tables 9-2 and 9-3 reflect both previous annual costs and projected annual spend:

Table 9-2 Actual Expenditures

	Dist. Feeder	Dist. Substation	Trans. Lines	Trans. Substation
2009	$27.3M	$5.2M	$27.2M	$20.2M
2010	$15.4M	$5.2M	$40.6M	$10.5M
2011	$26.6M	$6.5M	$24.8M	$1.4M
2012	$19.2M	$4.6M	$33.5M	$4.7M
2013	$23.8M	$2.8M	$14.9M	$4.8M

Table 9-3 Planned Expenditures

	Dist. Lines	Dist. Substation	Trans. Lines	Trans. Substation
2014	$28.9M	$4.3M	$8.5M	$4.5M
2015	$27.0M	$5.8M	$7.4M	$4.8M
2016	$27.0M	$7.9M	$5.2M	$4.8M
2017	$27.5M	$6.7M	$8.8M	$2.3M
2018	$27.6M	$4.5M	$8.6M	$4.3M

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CHAPTER 10

GENERATION PLANNING

INTRODUCTION

The purpose of the generation plan is to develop the optimal strategy for adding the resources as necessary to reliably meet the future demand requirements of Vectren's electric customers. The plan is integrated in that both supply-side and demand-side alternatives were considered and evaluated. The optimal plan is defined as the best possible combination of resource additions that result in reliable service at the lowest cost to customers over the twenty year planning horizon. The optimal resource plan is determined by evaluating all of the possible resource combinations and choosing the plan that minimizes the Net Present Value (NPV).

APPROACH

The process of determining the best resource plan was approached as an optimization problem. Vectren's consultant, Burns and McDonnell, utilized the Strategist software tool developed and supported by Ventyx of Atlanta, GA. Strategist is a strategic planning system that integrates financial, resource, marketing, and customer information. Strategist allows for addressing all aspects of integrated planning at the level of detail required for informed decision making. Strategist handles production costing, capital expenditure and recovery, financial and tax implications, and optimization all within one software system.

An optimization method has three elements: an objective, constraints, and alternatives. For the electric integration process, the three elements can be summarized as follows:

Objective

The objective of the integration analysis was to determine the optimal resource plan by minimizing the NPV. For the purposes of this discussion, the planning period NPV is defined as the net present value of operating costs including fuel plus capital costs. Power purchases and sales are also included in the NPV analysis for the 20 year period, 2015 – 2034. NPV numbers were developed by integrating three scenarios with four different energy forecasts. The generation options within the scenarios, along with

the alternative generation (discussed in Chapter 6 Electric Supply Analysis and Chapter 7 Renewables and Clean Energy), additional DSM (discussed in Chapter 8 DSM Resources) and purchasing capacity from the market were compared against the capacity needs of the four energy forecasts yielding twelve plans of the least cost NPV. These twelve plans were then vetted against multiple sensitivities to see which plan would be the most versatile given a wide range of possible outcomes.

Constraints

The primary constraint was to maintain a minimum planning reserve margin (PRM). MISO has moved to an unforced capacity (UCAP) PRM in the last couple of years. The UCAP accounts for the amount of installed capacity (ICAP) or nameplate capacity available at system's mega-watt peak hour of the peak day after discounting for the time that the generating facility is not available due to historical outages such as maintenance and repairs. The UCAP PRM is subject to change each year depending on MISO's projected need. For the year 2014, MISO set forth a UCAP PRM of 7.3%. This means that Vectren must maintain at least 7.3% over the peak demand of its customers on a UCAP basis. The goal is to determine the minimum planning reserve margin that would result in the MISO system experiencing less than one loss of load event every ten years. Other constraints include the project development and build times for new construction alternatives, transmission import constraints, reliability considerations, and the characteristics of existing resources and demand.

Alternatives

A broad array of alternative generation and DSM was included in the optimization analysis. The full range of supply-side resource alternatives were identified and discussed in Chapter 6 Electric Supply Analysis. Likewise, the demand-side alternatives were covered in Chapter 8 DSM Resources.

DISCUSSION OF KEY INPUTS AND ASSUMPTIONS

The NPVs were determined by evaluating all of the pertinent costs that could impact future resource additions. The NPVs include the operating and maintenance (O&M) costs of existing and new facilities and the financial costs associated with capital investments. O&M costs include both fixed and variable expenses such as fuel, production labor, maintenance expenses, and chemical costs for environmental controls.

Please note that this analysis does not explicitly include all of Vectren's Power Supply and Energy Delivery costs related to serving retail electric customers. Costs that would be common to all of the potential resource plans (e.g., allocated admin and general costs, transmission and distribution costs, other embedded costs, etc.) were not included because they had no impact on the comparative economic analysis. The considered costs were primarily related to O&M and new capital associated with power generation activities. Therefore, comparisons between the base case and alternate scenarios should be viewed within this context.

Electric Demand Forecast

As mentioned in the prior section, the electric peak and energy forecast is discussed in detail in Chapter 5 Sales & Demand Forecast. The four demand forecast results used in the optimization analysis are summarized in Table 5-3. The four forecasts consist of a base, a low, and two separate high demand forecasts.

Characteristics of Existing Generating Resources

The operating characteristics of existing Vectren owned electric generating resources, as they were simulated for the purposes of the integration analysis are summarized in Table 10-1. These characteristics were applied to all years of the study period.

Table 10-1 Characteristics of Existing Generating Resources

Resource Name	UCAP (MW)	Primary Fuel	Resource type	EFOR (%)	Estimated Full Load Heat Rate (Btu/kwhn)
AB Brown 1	228	coal	steam	4.9	10,800
AB Brown 2	233	coal	steam	3.6	10,700
FB Culley 2	83	coal	steam	7.4	11,700
FB Culley 3	257	coal	steam	4.3	10,400
Warrick 4	135	coal	steam	10.2	10,200
AB Brown 3	73	gas	combustion turbine	0.0	12,000
AB Brown 4	69	gas	combustion turbine	3.6	11,700
BAGS 2	59	gas	combustion turbine	3.6	13,000
Northeast 1	9	gas	combustion turbine	2.7	15,000
Northeast 2	9	gas	combustion turbine	2.7	15,000
Blackfoot[1]	3	landfill gas	IC engine	5.0	9,000

Existing Purchased Power

Vectren has an existing and ongoing firm purchased capacity and energy commitment with the Ohio Valley Electric Corporation (OVEC). The UCAP of this commitment equals 30 MW. It was also assumed that this resource would be present throughout the 20-year study period.

Finally, as discussed in Chapter 7 Renewables and Clean Energy, Vectren has two long-term purchase power agreements for wind energy. These purchases were assumed to be in place for the entire IRP study period. The UCAP for Vectren's wind capacity is approximately 9.1% or 7.3 MW of the 80 MW of wind.

[1] Blackfoot is "behind the meter" and is accounted for as a credit to load

Fuel Prices

The cost of fuel is one of the largest cost components of the analysis. Therefore, the assumptions that are made regarding future fuel prices are a very important variable for developing a least cost resource plan.

Vectren utilized data from three sources to develop the fuel price forecasts for this IRP. The natural gas price forecast is an average of U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2014 Reference case[1], Wood Mackenzie long term forecast[2], and Black & Veatch's natural gas forecast[3]. Basis assumptions were applied to simulate the delivered burner tip gas cost to Vectren generators. To develop the coal price forecast; Vectren utilized the same three sources and averaged their coal forecasts together to develop the IRP forecast.

An important factor to consider when developing or analyzing long-term fuel price forecasts is the impact that the Clean Power Plan (discussed in Chapter 4 Environmental) may have on the forecasts. Another factor to consider is the uncertainty of markets in the future. The further out the forecast goes the more uncertain the projection becomes. Market conditions and customer demand are continually evaluated when procuring fuel for use in Vectren's electric generation units. Vectren maintains an adequate supply of coal in physical inventory on the ground at each of plant location to ensure reliable service to customers as a prudent contingency in the event of unforeseen supply interruptions due to weather, labor, etc. Table 10-2 shows the average annual delivered base case fuel price forecasts for coal and natural gas.

[1] Included in the Technical Appendix, section E
[2] Wood Mackenzie long term forecasts are subscription based and proprietary.
[3] Black and Veatch's long term forecasts are subscription based and proprietary.

Table 10-2 Base Fuel Price Projection

IRP Base Case Delivered Forecasts		
	Real 2014$/MMBtu	
Year	Coal	Natural Gas
2015	2.57	4.65
2016	2.54	4.86
2017	2.54	5.03
2018	2.59	5.31
2019	2.62	5.46
2020	2.60	5.66
2021	2.61	5.71
2022	2.64	5.72
2023	2.63	5.82
2024	2.67	6.06
2025	2.65	6.15
2026	2.65	6.28
2027	2.67	6.33
2028	2.68	6.43
2029	2.71	6.59
2030	2.71	6.72
2031	2.71	6.82
2032	2.74	6.99
2033	2.80	7.16
2034	2.81	7.35

Environmental Considerations

Chapter 4 Environmental discusses environmental issues in detail. Variable cost impacts associated with running FGD, SCR and other environmental equipment were included in the revenue requirement calculations as part of the integration analysis.

Financial Assumptions

The financial assumptions with respect to capital investments required to add new construction resource alternatives are summarized in Chapter 6 Electric Supply Analysis. Additional information can be found in the Technology Assessment in the Technical Appendix, section B. Additional information regarding the projected costs energy efficiency programs can be found in Chapter 8 DSM Resources. The declining

costs of utility scale solar (50 MW blocks) were modeled as an asymptotic curve beginning at $1,880 per KWac in 2014 and declining to $1,500 per KWac in 2020 and staying flat in real terms for the remainder of the planning horizon.

General Inflation Forecast

The general inflation forecast used in the assumptions is 1.6%. This inflation rate comes from the Federal Reserve Bank of St. Louis. This is also very close to the compound annual growth rate used in the EIA AEO 2014 for the years that are covered in the IRP.

Additional Considerations

The energy industry landscape has been changing at a fast pace, affecting both electric utilities and their customers. Although there is little clarity on how the state of Indiana will choose to implement the EPA's Clean Power Plan, it could drive substantial changes to the mix of resources available to meet customer electric demand. The EPA's MATS rule has resulted in numerous announcements of coal plant retirements across the US. As a result, MISO is predicting potential capacity shortfalls in the next few years. With low natural gas prices, some large industrial customers are considering generating their own electricity, which could affect future energy forecasts. Additionally, the proportion of residential and commercial customers installing solar panels to generate electricity continues to rise, which will effectively lower future demand for energy from the system.

Vectren has taken all of these factors into consideration in the 2014 IRP by either modeling assumed inputs, as is the case with customer-owned solar panels, or outside of modeling in the risk analysis. The combination of these factors makes the future very uncertain. Vectren continues to evaluate these developments and plan for the future with an emphasis on keeping costs as low and fair as possible for all customers, while maintaining reliability and meeting regulations.

INTEGRATION ANALYSIS RESULTS

Base Demand Forecast (Growth Scenario 1)

Plans A-1 B-1 and C-1 represent the base demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast. Therefore, the resource additions in plan C-1 are driven by the renewable energy constraints unique to the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or demand side resources that resulted in the lowest NPV.

Table 10-3 shows the resource plan for the base demand forecast and the associated NPV's. Plans A-1 and B-1 are essentially the same with only about 0.5 % difference in the NPV's. Plan C-1 which is 2.4% higher reflects the capital expense of additional renewable resources. All three plans are the same through 2019 where a DSM block is selected in the more expensive plan C-1. This will be re-evaluated in future IRP cycles as various uncertainty factors are resolved over time.

Table 10-3 Base Demand Forecast (Growth Scenario 1)

Energy Sales Case :	Base Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A1	Plan B1	Plan C1
2015			
2016			
2017			
2018			
2019			0.5% DSM[2] Block (2019-2034)
2020		Shutdown FB Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV (1x50 MW)
2025			Solar PV[3] (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[4]	$4,874,614	$4,848,213	$4,991,616
% Difference	0.0%	-0.5%	2.4%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Net Present Value inclusive of wholesale adjustment (2014 $)

Low Demand Forecast (Growth Scenario 2)

Plans A-2, B-2 and C-2 represent the low demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast. Therefore, the resource additions in plan C-2 are driven by the renewable energy constraints unique to the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or additional demand side resources that resulted in the lowest NPV.

Table 10-4 shows the resource plan for the base demand forecast and the associated NPV's. Plans A-2 and B-2 are essentially the same with only about 0.7 % difference in the NPV's. Plan C-2 which is 2.1% higher reflects the capital expense of additional renewable resources. All three plans are the same through 2017 where a DSM block is selected in the more expensive plan C-2.

Table 10-4 Low Demand Forecast (Growth Scenario 2)

Energy Sales Case :	Low Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A2	Plan B2	Plan C2
2015			
2016			
2017			0.5% DSM[2] Block (2017-2034)
2018			
2019			
2020		Shutdown FB Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			
2025			Solar PV[3] (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[4]	$4,771,789	$4,739,585	$4,871,859
% Difference	0.0%	-0.7%	2.1%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Net Present Value inclusive of wholesale adjustment (2014 $)

High (modeled) Demand Forecast (Growth Scenario 3)

Plans A-3, B-3 and C-3 represent the High (modeled) demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast as can be seen in case A-3. However, the assumed retirement of Culley unit 2 in 2020 in conjunction with the increase in load drives some capacity additions in case B-3. The resource additions in plan C-3 are driven by the renewable energy constraints unique to the renewable portfolio scenario. However, the timing of the resources is slightly different due to interim renewable constraint in the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side or additional demand side resources that resulted in the lowest NPV.

Table 10-5 shows the resource plan for the high (modeled) demand forecast and the associated NPV's. Plans A-3 and B-3 are essentially the same with only about 0.3% difference in the NPV's. Plan C-3 which is 2.1% higher reflects the capital expense of additional renewable resources. The higher load growth in combination with the assumed retirement of Culley 2 suggests that more energy efficiency measures should be implemented soon if that combination of were to occur. However, a mere 0.2% difference in the NPV's between plan A-3 and B-3 is not enough to drive such a major change.

Table 10-5 High (modeled) Demand Forecast (Growth Scenario 3)

Energy Sales Case :	High (modeled) Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A3	Plan B3	Plan C3
2015		0.5% DSM[2] Block (2015-2034)	
2016			
2017			
2018			
2019			
2020		0.5% DSM Block ('20-'34) Shutdown FB Culley 2	1.0% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV[3] (1x50 MW)
2025			Solar PV (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031		Mkt Cap[4] (2MW)	
2032		Mkt Cap (6MW)	
2033		Mkt Cap (8MW)	
2034		Solar PV (1x50 MW)	
NPV[5]	$5,064,159	$5,049,163	$5,168,352
% Difference	0.0%	-0.3%	2.1%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] PV = Photovoltaic
[4] Mkt Cap = Market Capacity Purchase
[5] Net Present Value inclusive of wholesale adjustment (2014 $)

High (large load) Demand Forecast (Growth Scenario 4)

Plans A-4, B-4 and C-4 represent the high (large load) demand forecast in combination with the three basic portfolio themes of "A"- Base (serve customers with existing resources & DSM), "B" – FB Culley 2 Unit Retirement Scenario and "C" – Renewable Portfolio Standard. It should be noted that no new capacity is required under this load forecast as can be seen in case A-4. However, the assumed retirement of Culley unit 2 in 2020 in conjunction with the increase in load drives a capacity addition in case B-4. The resource additions in plan C-4 are driven by the renewable energy constraints unique to the renewable portfolio scenario. However, the timing of the resources is slightly different due to interim renewable constraint in the renewable portfolio scenario.

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side resources that resulted in the lowest NPV.

Table 10-6 shows the resource plan for the high (large load) demand forecast and the associated NPV's. Plan A-4 is the lowest cost plan under this load growth scenario, beating plans B-4 and C-4 by 1.9% and 2.5% respectively. Plans B-4 and C-4 reflect the capital expense of additional resources. These scenarios are significantly higher than plan A-4 in the near term. Note that all three plans are the same through 2018 where a DSM block is selected in the more expensive plan C-1.

Table 10-6 High (large load) Demand Forecast (Growth Scenario 4)

Energy Sales Case :	High (large load) Demand Forecast		
Scenario :	Base	FB Culley 2 Unit Retirement	RPS[1]
Plan ID :	Plan A4	Plan B4	Plan C4
2015			
2016			
2017			
2018			0.5% DSM[2] Block (2018-2034)
2019			
2020		Block of CCGT[3] (200 MW) Shutdown F.B Culley 2	0.5% DSM Block (2020-2034)
2021			
2022			
2023			
2024			Solar PV[4] (2x50 MW)
2025			Solar PV (4x50 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
NPV[5]	$5,156,487	$5,254,385	$5,283,860
% Difference	0.0%	1.9%	2.5%

[1] RPS = Renewable Portfolio Standard
[2] DSM = Demand Side Management
[3] CCGT = Combined Cycle Gas Turbine
[4] PV = Photovoltaic
[5] Net Present Value inclusive of wholesale adjustment (2014 $)

Integration Analysis Results Summary

As mentioned previously, the Strategist output is the lowest-cost plan for customers. The plan summary table 10-7 shows the costs for each plan A1-C4. Note that the costs represent the total present day value of serving Vectren customers under various portfolio mixes to meet customer demand for each scenario. The costs include capital for new resources, operating and maintenance costs, etc. for each plan over the 20-year forecast. Renewable Portfolio Standard (RPS) scenario plans were all the most expensive because they require new generation to be built and additional energy efficiency programs, which are paid for by customers, to meet the renewables requirement. Although no fuel is consumed by renewable resources, there are still costs associated with building and maintaining facilities. Renewables are intermittent resources, making them generally more expensive to help meet capacity requirements. Additionally, retiring FB Culley 2 prematurely, in the event of a large customer addition, could be very costly to customers. The cost of serving customers with existing resources, compared to retiring FB Culley 2 in 2020, were essentially the same under the low, base and high electric forecasts. Due to the risks associated with prematurely retiring FB Culley 2, discussed below in the Sensitivity and Risk Analysis section of this report, Vectren plans to serve customers with existing generation, plan A1 (Base electric forecast and Base scenario) in the near term. Vectren will conduct IRPs in 2016 and 2018. The plans are very similar or identical during the first few years. Therefore, no immediate action is required. The plans will be re-evaluated in future IRP cycles as various uncertainty factors are resolved over time.

Table 10-7 Plan Summary Table

		A	B	C
		Base Scenario	FB Culley 2 Unit Retirement Scenario	RPS Scenario
1	Base Demand Forecast	$4,874,614 0.0%	*$4,848,213* *-0.5%*	$4,991,616 2.4%
2	Low Demand Forecast	$4,771,789 0.0%	*$4,739,585* *-0.7%*	$4,871,859 2.1%
3	High (modeled) Demand Forecast	$5,064,159 0.0%	*$5,049,163* *-0.3%*	$5,168,352 2.1%
4	High (large load) Demand Forecast	*$5,156,487* *0.0%*	$5,254,385 1.9%	$5,283,860 2.5%

Note: Percent difference is reported on the same sales forecast basis
NPV = 2014 $000's @ 5.6%

SENSITIVITY AND RISK ANALYSIS

Each plan was subjected to additional risk sensitivities to determine which plan is the lowest cost over a wide range of possible future risks. As previously mentioned, resource modeling requires a large number of inputs and assumptions over a 20-year timeframe. It is impossible to precisely predict future prices of commodities such as fuel and other assumed economic factors such as carbon prices. Therefore, several future possibilities were considered. The 12 expansion plan scenarios were stress tested in regard to their sensitivity to variation in natural gas prices, coal prices, electric energy market prices, carbon prices, and capital costs of new resources. One additional stress test was added for a high regulation cost uncertainty. The parameters for these stress tests can be seen in table 10-8. The range of cost sensitivities for natural gas, coal and electric energy were stressed +/- 20%, which is consistent with the sensitivity

percentages used in the MISO Transmission Expansion Plan 15 (MTEP 15). The large MISO stakeholder constituency reaches consensus on these ranges; therefore, Vectren believes that these are reasonable ranges. At the suggestion of some stakeholders, Vectren used the Synapse 2013 mid case CO_2 pricing as the high sensitivity and the MTEP 15 CO_2 mid case as the low sensitivity. Capital costs for new resources were stressed +30/-10 percent as it is much more common throughout the industry to see cost underestimates than cost overestimates upon actual project completions. The high regulation cost was a stress test of adding the capital for a cooling tower at FB Culley in 2022.[1]

[1] [1] While Vectren continues to believe that it is unlikely that the state will require a cooling water tower retrofit at Culley under regulations recently finalized implementing Clean Water Act §316b, Vectren included this as a high cost sensitivity. Construction costs would commence starting in 2022, after the required ecological and technological study feasibility period.

Table 10-8 Sensitivity Summary Table (Used For Stress Tests)

Sensitivities	High	Low	Potential Sources
Natural Gas Forecasts	+20%	-20%	MTEP 15
Coal Forecast	+20%	-20%	MTEP 15
Market Energy Forecast	+20%	-20%	MTEP 15
CO_2 Forecast	$15.5/Ton	$10.3/Ton	Synapse, MTEP 15
Capital Cost	+30%	-10%	Burns and McDonnell Tech Assessment
High Regulation Cost*	$40m	-	Future Regulatory Scenario[1]

[1] While Vectren continues to believe that it is unlikely that the state will require a cooling water tower retrofit at Culley under regulations recently finalized implementing Clean Water Act §316b, Vectren included this as a high cost sensitivity. Construction costs would commence starting in 2022, after the required ecological and technological study feasibility period.

Stress Test of Base Demand Forecast (Growth Scenario 1)

Plan A-1 B-1 and C-1 stress test results are shown in table 10-9. Similarly to the results shows in table 10-3, plans A1 and B1 are essentially the same over a wide variety of possible future sensitivities. Plan C1 remains the most expensive.

Table 10-9 Stress Tests Results for Base Demand Forecast (Growth Scenario 1)

	Base (Plan A1)	FB Culley 2 Unit Retirement (Plan B1)	RPS (Plan C1)
Base	$4,874,614	$4,848,213	$4,991,616
High Gas	$4,908,570	$4,883,867	$5,024,377
Low Gas	$4,826,209	$4,797,668	$4,944,615
High Coal	$5,268,181	$5,221,310	$5,381,876
Low Coal	$4,471,184	$4,466,032	$4,591,643
High Market	$4,727,528	$4,737,505	$4,821,102
Low Market	$4,957,322	$4,895,134	$5,099,072
Low Carbon Price	$4,704,763	$4,681,858	$4,836,921
High Carbon Price	$5,336,590	$5,302,147	$5,415,470
High Capital Cost	$4,874,614	$4,848,213	$5,047,790
Low Capital Cost	$4,874,614	$4,848,213	$4,972,892
High Regulation Cost	$4,900,481	$4,867,614	$5,017,484

Stress Test of Low Demand Forecast (Growth Scenario 2)

Plan A-2 B-2 and C-2 stress test results are shown in table 10-10. Similarly to the results shows in table 10-4, plans A2 and B2 are essentially the same over a wide variety of possible future sensitivities. Plan C2 remains the most expensive.

Table 10-10 Stress Tests Results for Low Demand Forecast (Growth Scenario 2)

	Base (Plan A2)	FB Culley 2 Unit Retirement (Plan B2)	RPS (Plan C2)
Base	$4,771,789	$4,739,585	$4,871,859
High Gas	$4,804,936	$4,774,367	$4,904,004
Low Gas	$4,724,382	$4,690,021	$4,825,580
High Coal	$5,162,681	$5,110,118	$5,259,798
Low Coal	$4,371,289	$4,360,256	$4,474,450
High Market	$4,610,079	$4,613,296	$4,689,627
Low Market	$4,870,385	$4,803,750	$4,992,076
Low Carbon Price	$4,608,762	$4,579,376	$4,722,725
High Carbon Price	$5,215,962	$5,175,885	$5,282,560
High Capital Cost	$4,771,789	$4,739,585	$4,915,631
Low Capital Cost	$4,771,789	$4,739,585	$4,857,268
High Regulation Cost	$4,797,656	$4,758,986	$4,897,726

Stress Test of High (modeled) Demand Forecast (Growth Scenario 3)

Plan A-3 B-3 and C-3 stress test results are shown in table 10-11. Similarly to the results shows in table 10-5, plans A3 and B3 are essentially the same over a wide variety of possible future sensitivities. Plan C3 remains the most expensive.

Table 10-11 Stress Tests Results for High (modeled) Demand Forecast (Growth Scenario 3)

	Base (Plan A3)	FB Culley 2 Unit Retirement (Plan B3)	RPS (Plan C3)
Base	$5,064,159	$5,049,163	$5,168,352
High Gas	$5,099,475	$5,086,180	$5,202,306
Low Gas	$5,014,048	$4,997,322	$5,119,822
High Coal	$5,462,101	$5,425,041	$5,562,663
Low Coal	$4,655,886	$4,663,907	$4,763,874
High Market	$4,943,471	$4,956,522	$5,022,702
Low Market	$5,116,818	$5,076,415	$5,248,386
Low Carbon Price	$4,881,866	$4,876,097	$4,999,192
High Carbon Price	$5,563,573	$5,525,040	$5,628,969
High Capital Cost	$5,064,159	$5,050,009	$5,224,526
Low Capital Cost	$5,064,159	$5,048,881	$5,149,626
High Regulation Cost	$5,090,027	$5,068,564	$5,194,219

Stress Test of High (large load) Demand Forecast (Growth Scenario 4)

Plan A-4 B-4 and C-4 stress test results are shown in table 10-12. Similarly to the results shows in table 10-6, plan A4 is significantly less expensive in the near term than plans B4 and C4.

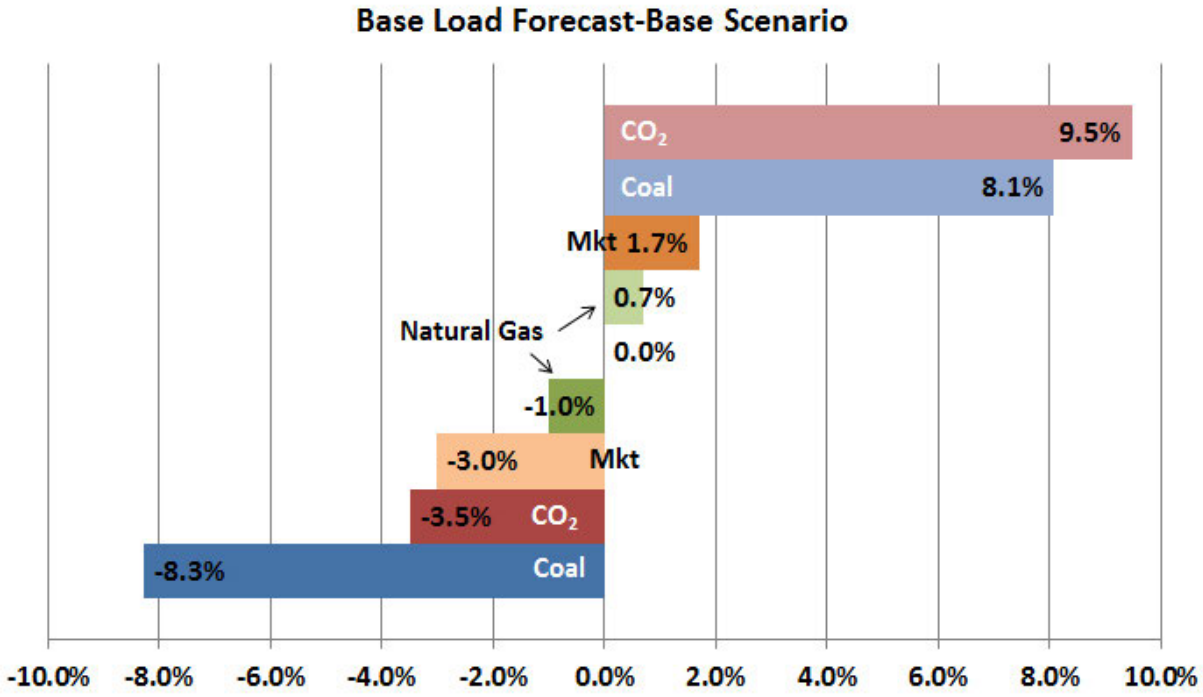
Table 10-12 Stress Tests Results for High (large load) Demand Forecast (Growth Scenario 3)

	Base (Plan A4)	FB Culley 2 Unit Retirement (Plan B4)	RPS (Plan C4)
Base	$5,156,487	$5,254,385	$5,283,860
High Gas	$5,192,745	$5,317,261	$5,318,391
Low Gas	$5,105,576	$5,163,552	$5,234,683
High Coal	$5,556,624	$5,646,923	$5,679,926
Low Coal	$4,745,742	$4,853,216	$4,877,383
High Market	$5,049,403	$5,098,566	$5,147,775
Low Market	$5,194,651	$5,328,227	$5,353,361
Low Carbon Price	$4,970,102	$5,093,626	$5,112,573
High Carbon Price	$5,665,492	$5,711,718	$5,749,275
High Capital Cost	$5,156,487	$5,322,627	$5,441,585
Low Capital Cost	$5,156,487	$5,231,638	$5,240,428
High Regulation Cost	$5,182,354	$5,273,786	$5,309,727

Relative Influence of Stress Test Factors

The relative influence of the stress tests on the net present values can be seen in table 10-13.

Table 10-13 Relative Influence of Stress Tests on Net Present Values



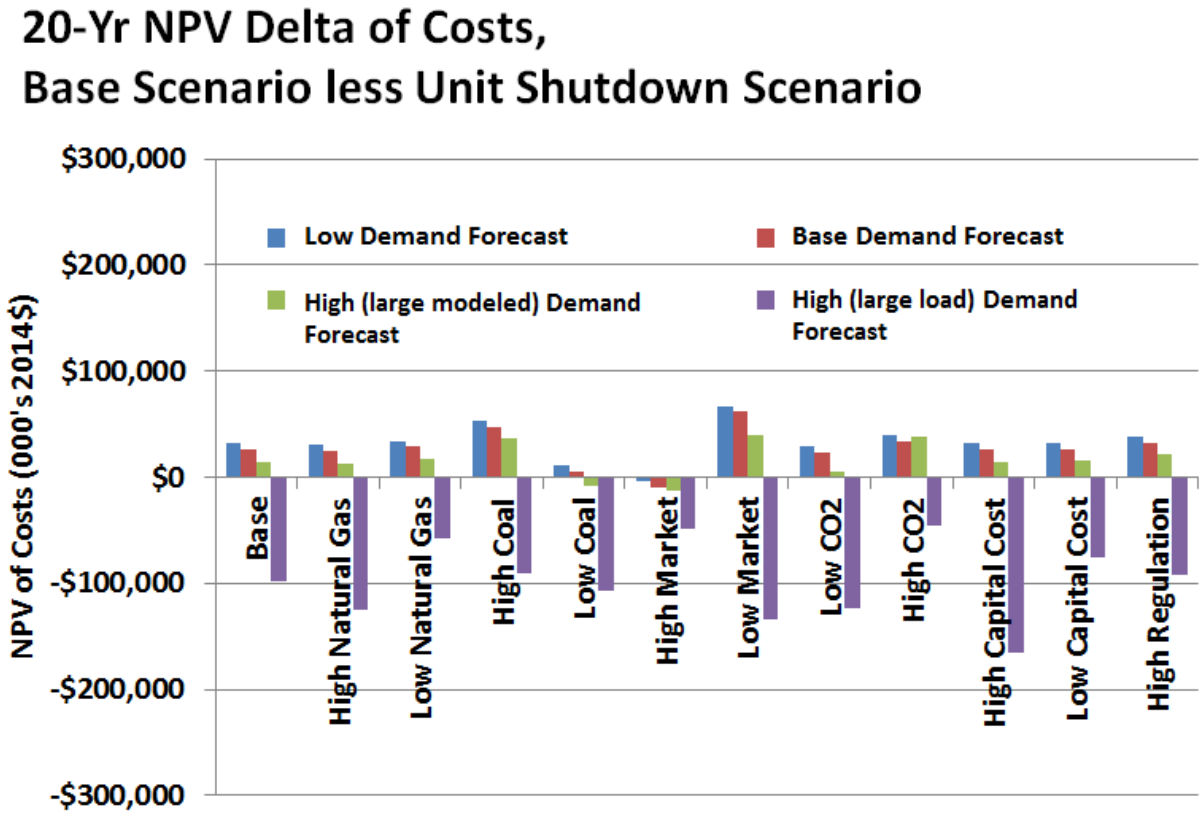
Risk Comparison

Under most risk factors, the cost of continuing operation of FB Culley or retirement in 2020 are essentially the same. As illustrated below in Table 10-14, the cost risk to customers if Vectren prematurely retires F.B. Culley 2 is potentially large under the high (large load) demand forecast.

Table 10-14 shows the risk comparison across all sensitivities and sales forecasts for the base scenario compared to the coal retirement scenario. This graph illustrates that the differences across three of the four sales forecasts are relatively small compared to the large savings in the high (large load) demand forecast case. Stated differently, the positive bars represent the extra cost of not retiring FB Culley 2 under 3 of the 4

demand scenarios. The negative bars represent the savings under 1 of the 4 sales scenarios by not retiring FB Culley 2 in 2020. The high (large load) growth scenario savings are much greater across all sensitivities by not retiring a unit. Vectren is actively working to attract new industrial customers through economic development activities in southwestern Indiana. If a large customer chooses to locate within the Vectren electric service area, it will be significantly less expensive to serve that additional load with existing resources in the near term.

Table 10-14 Comparison of Risks



Therefore, there are significant risks to retiring Culley unit 2 in the next few years. Vectren is making no decision at this time on a retirement date for several reasons. The graph above illustrates the risk of the high large load addition. Other significant risks include how the state of Indiana implements the Clean Power Plan, load uncertainties,

and potential MISO shortfalls. There is little clarity on how Indiana intends to implement CO_2 guidelines. Depending on the direction that is taken, the plan may vary. Second, one of Vectren's largest customers is still finalizing plans for their co-generation unit. Vectren needs to better understand how this will affect the load forecast. Finally, with several coal plants shutting down within the MISO market, there is potential that not enough generation will be available to reliably serve the overall market. A decision about the assumed retirement of FB Culley 2 in 2020 in scenarios B1-B4 will not be made until near-term risk factors become clearer.

CONCLUSION

Based on Vectren's electric demand forecast, which includes cost effective DSM energy efficiency programs for customers, Vectren does not require additional resources. The IRP analysis indicates it is essentially the same cost to continue to operate FB Culley 2 or retire it in the near future. The decision to retire this unit is subject to a number of risks and uncertainties. Vectren is making no decision at this time on a retirement date.

As mentioned in the Risk Analysis section of this report, there are four major risks of retiring FB Culley 2 in the next few years:

1. How Indiana intends to implement CO_2 guidelines, the EPA's Clean Power Plan (111d)
2. Uncertainty about customer load due to the installation of a large co-generation unit
3. The possibility of a new large customer addition
4. Uncertainty around potential capacity shortfalls within the MISO market

Based on the risk associated with retiring FB Culley 2, Vectren will keep plan A-1 as the plan of choice in the near term, but will continue to evaluate the changing technology, environmental and regulatory developments, as well as customer costs and

reliability needs. More time and analysis is needed to make a decision on the timing of retiring FB Culley 2. Note that there will be two more IRPs prepared prior to 2020.

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CHAPTER 11

ACTION PLAN

INTRODUCTION

These are the next steps the organization will take to achieve a reasonable long-term cost to retail customers with full consideration of the complex issues facing the industry in the next few years.

SUPPLY-SIDE RESOURCES

The overall objective of this study and review is to ensure that Vectren is properly positioned to meet its obligation to serve the needs of its Indiana retail customer base. Over the next several years, Vectren will continue to monitor changing market factors and risks including, but not limited to, increased environmental regulations including the EPA Clean Power Plan, large customer load, fuel price volatility, escalation of capital costs, increased emphasis on conservation measures, demand response, Smart Grid/AMI, and RTO related developments, particularly the possibility of MISO shortfalls. These items will be monitored both for their potential impact on future capacity needs and their impact on the operation of existing assets.

Vectren projects to have the generating capacity needed to meet the needs of its customers without adding any additional assets in all scenarios. All 12 plans explored are very similar or identical during the first few years. No immediate action is required. Vectren will conduct additional analysis, including another IRP in 2016. A decision about the assumed retirement of FB Culley 2 in 2020 will not be made until near term risk factors become clearer.

DEMAND-SIDE RESOURCES

Vectren plans to continue to pursue DSM, energy efficiency, and demand response opportunities by working through collaborative efforts with the IURC and OUCC. Vectren will continue to implement the 2015 DSM Plan as filed under Cause No. 44495, which was recently approved by the Commission. The programs outlined in the 2015 DSM Plan are designed to cost effectively reduce energy use and electric demand by approximately 1% of eligible retail sales. While Vectren's current resources are

adequate to meet the needs of its customers, Vectren believes that conservation is in their customers' best interest. Helping customers learn to conserve energy will benefit customers through lower bills, the environment through lower emissions, and rates through the reduced need for additional system capacity in the future.

Vectren is in the process of developing a three-year Action Plan for 2016-2018 electric DSM programs. The programs outlined in this three-year Action Plan will be designed to reduce energy use by approximately 1– 1.5% of eligible retail sales. There are several variables that currently exist that may have impact on this planning process. The EPA Clean Power Plan proposal, Federal appliance and equipment minimum efficiency standards and state legislation relating to energy efficiency could all impact the savings goals for the next three years. Vectren is currently monitoring such rules and regulations and will continue to incorporate these factors into this planning process, as required.

Vectren will closely monitor trends regarding Smart Grid/AMI throughout the country. Vectren will work collaboratively with key stakeholders to determine the appropriate implementation strategy for Smart Grid/AMI in the Vectren territory.

TRANSMISSION AND DISTRIBUTION

Vectren will work closely with MISO to determine those transmission projects that will improve overall grid reliability within its service territory and those in the surrounding area. Vectren will implement system upgrades as needed to ensure reliable service to its customers. In addition, ongoing internal studies will monitor additions of industrial and commercial load in different locations within the Vectren service territory.

Detailed budgets for the short-term plan will be developed during Vectren's normal budgeting process.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 108
Vectren 2016 IRP

2016 Integrated Resource Plan



VECTREN
Live Smart

By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

December 16, 2016

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Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4	**Methodology and documentation requirements**	
	(a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences. (1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request as part of a contemporary issues meeting. The summary shall describe, in simple terms, the IRP public advisory process, if applicable, and core IRP concepts, including resource types and load characteristics. (2) The utility shall utilize a simplified format that visually portrays the summary of the IRP in a manner that makes it understandable to a non-technical audience. (3) The utility shall make this document readily accessible on its website.	Executive Summary and a separate document on www.vectren.com/irp
	(b) An IRP must include the following: (1) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Included throughout the IRP

Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4 Cont.	(2) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be referenced. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP, or as specified by the commission.	Included throughout the IRP and Technical Appendix
	(3) A description of the utility's effort to develop and maintain a data base of electricity consumption patterns, by customer class, rate class, NAICS code, and end-use. The data base may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	10.1.1.1; Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report
	(4) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	10.1.2
	(5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	4.4.1; 4.4.2; 4.4.3

Rule Reference	Rule Description	Report Reference (Outline Section)
	(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	6.1; 6.2
	(7) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	8.2.10
	(8) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission regulated through an emission allowance system have been taken into account and influenced the IRP development.	1.3.1.1; 7.3.4; 10.2; 10.2.1
	(9) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	2.2; 7.2.1; 8
170 IAC 4-7-4 Cont.	(10) A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715: (A) Most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The simulation must include the capability of meeting the standards of the North American Electric Reliability Corporation (NERC).	5.4; 10.6

Rule Reference	Rule Description	Report Reference (Outline Section)
	(C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it. (D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.	
	(11) An explanation of the contemporary methods utilized by the utility in developing the IRP, including a description of the following:	
	(A) Model structure and reasoning for use of particular model or models in the utility's IRP.	4.3; 5.2.3.3; 7.1.1.1; 7.2.1.1; 10.5
	(B) The utility's effort to develop and improve the methodology and inputs for its:	1.2.2
	(i) forecast;	4.2; 4.4.2; 6.1; 6.2
	(ii) cost estimates;	5.2
	(iii) treatment of risk and uncertainty; and	2; 6.2; 7; 8.1; 8.2
	(iv) evaluation of a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:	
	(AA) transmission; and	5.4.3; 8.2.7; 10.6
	(BB) generation.	5.1.5.2; 7.3.5; 8.2.3

Rule Reference	Rule Description	Report Reference (Outline Section)
170 IAC 4-7-4 Cont.	(12) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	10.2.4
	(13) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically and may be a separate file from the IRP. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Technical Appendix Attachment4.2 2015 Vectren Hourly System Load Data
	(14) Publicly owned utilities shall provide a summary of the utility's: (A) most recent public advisory process; (B) key issues discussed; (C) how they were addressed by the utility.	3; Technical Appendix Attachment 3.1 Stakeholder Materials
170 IAC 4-7-5	**Energy and demand forecasts**	
	(a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy	

Rule Reference	Rule Description	Report Reference (Outline Section)
	usage which includes the following:	
	(1) Historical load shapes, including, but not limited to, the following:	Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report
	(A) Annual load shapes.	
	(B) Seasonal load shapes.	
	(C) Monthly load shapes.	
	(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	
	(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	
	(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	Technical Appendix Attachment 4.1 2016 Long-Term Electric Energy and Demand Forecast Report; Technical Appendix Attachment 7.2 Balance of Loads and Resources
	(4) Actual and weather normalized energy and demand levels.	10.1.3
170 IAC 4-7-5 Cont.	(5) A discussion of all methods and processes used to normalize for weather.	10.1.3; 10.1.1.3
	(6) A minimum twenty (20) year period for energy and demand forecasts.	4.5
	(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following: (A) Total system.	10.1.3

Rule Reference	Rule Description	Report Reference (Outline Section)
	(B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	
	(8) Justification for the selected forecasting methodology.	Technical Appendix Attachment 4.1 2016 Long Term Electric Energy and Demand Forecast
	(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(b)(2) of this rule.	
	(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Changes in technology. (5) Behavioral factors affecting customer consumption. (6) State and federal energy policies. (7) State and federal environmental policies.	4.5; 6.2.2.2
170IAC 4-7-6	**Resource Assessment**	
	(a) The utility shall consider continued use of an existing resource as a resource alternative in meeting future electric service requirements. The utility shall provide a description of the utility's existing electric power resources that must include, at a minimum, the following information:	5.1
	(1) The net dependable generating capacity of the system and each generating unit.	5.1

Rule Reference	Rule Description	Report Reference (Outline Section)
	(2) The expected changes to existing generating capacity, including, but not limited to, the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	5.1; 7
	(3) A fuel price forecast by generating unit.	6.1
170IAC 4-7-6 Cont.	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	10.2
	(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	10.6
	(6) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load	5.1.4; 5.1.5; Technical Appendix Attachment 5.1 Vectren South

Rule Reference	Rule Description	Report Reference (Outline Section)
	management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	Electric 2016-2017 DSM Plan
	The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall also be provided for each year of the planning period.	
	(b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's IRP shall, at a minimum, include the following:	5.1.5; 5.2.3; 5.2.4
	(1) A description of the demand-side program considered.	5.2.3; 5.2.4
	(2) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	10.3.4
	(3) The customer class or end-use, or both, affected by the program.	5.1.4; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Rule Reference	Rule Description	Report Reference (Outline Section)
	(4) A participant bill reduction projection and participation incentive to be provided in the program.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
170IAC 4-7-6 Cont.	(5) A projection of the program cost to be borne by the participant.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(6) Estimated energy (kWh) and demand (kW) savings per participant for each program.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(7) The estimated program penetration rate and the basis of the estimate.	Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(8) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	5.1.4; 5.2.3; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(c) A utility shall consider a range of supply-side resources including cogeneration and nonutility generation as an alternative in meeting future electric service requirements. This range shall include commercially available resources or resources the director may request as part of a contemporary issues technical conference. The utility's IRP shall include, at a minimum, the following:	5
	(1) Identify and describe the resource considered, including the following:	5; 10.6

Rule Reference	Rule Description	Report Reference (Outline Section)
	(A) Size (MW).	5
	(B) Utilized technology and fuel type.	5
	(C) Additional transmission facilities necessitated by the resource.	5.4.3
	(2) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	9.2.4
	(d) A utility shall consider new or upgraded transmission facilities as a resource in meeting future electric service requirements, including new projects, efficiency improvements, and smart grid resources. The IRP shall, at a minimum, include the following: (1) A description of the timing and types of expansion and alternative options considered. (2) The approximate cost of expected expansion and alteration of the transmission network. (3) A description of how the IRP accounts for the value of new or upgraded transmission facilities for the purposes of increasing needed power transfer capability and increasing the utilization of cost effective resources that are geographically constrained.	5.4.3
170IAC 4-7-6 Cont.	(4) A description of how: (A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and (B) RTO planning and implementation processes are used in and affect the IRP.	1.3.7; 4;6.1.3; 10.6.2
170 IAC 4-7-7	**Selection of future resources**	

Rule Reference	Rule Description	Report Reference (Outline Section)
	(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through 6(c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in, but not limited to, a resource summary table. The following information: (1) Significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge.	10.2; Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table
	(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	1.3.1; 6.1; 6.2; 7.3.4; 8.2.2; 10; Technical Appendix Attachment 3.1 Stakeholder Materials
	(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e): (1) Participant. (2) Ratepayer impact measure (RIM). (3) Utility cost (UC). (4) Total resource cost (TRC). (5) Other reasonable tests accepted by the commission.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Rule Reference	Rule Description	Report Reference (Outline Section)
	(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(d) A utility is required to:	
	(1) specify the components of the benefit and the cost for each of the major tests; and	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(2) identify the equation used to express the result.	5.2.3.7; Technical Appendix Attachment: 5.1 Vectren South Electric 2016-2017 DSM Plan
170 IAC 4-7-7 Cont.	(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	5.2.3.7; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
	(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8	**Resource integration**	
	(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.	7.1; 3.2; Technical Appendix Attachment 3.1 Stakeholder Materials

Rule Reference	Rule Description	Report Reference (Outline Section)
	(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:	8.2
	(1) Describe the utility's preferred resource portfolio.	8.2
	(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.	8.2
	(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.	5; 6; 7; 8.2
	(4) Demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply.	8.2
	(5) Discuss the utility's evaluation of targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	5; 8.2; 10.3; Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan
170 IAC 4-7-8 Cont.	(6) Discuss the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio. The discussion of the preferred resource portfolio shall include, where appropriate, the following: (A) Operating and capital costs. (B) The average cost per kilowatt-hour, which must be consistent with the electricity price assumption used to forecast the utility's	8.2; 9.2.5; 10; Technical Appendix Confidential Attachment 7.3 Portfolio Input-Output Report

Rule Reference	Rule Description	Report Reference (Outline Section)
	expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	
	(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost effective risk and uncertainty reduction, including the following. (A) Identification and explanation of assumptions. (B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to: See below. (i) regulatory compliance; (ii) public policy; (iii) fuel prices; (iv) construction costs; (v) resource performance; (vi) load requirements; (vii) wholesale electricity and transmission prices; (viii) RTO requirements; and (ix) technological progress. (C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.	7; 8.2; Technical Appendix Attachment 3.1 Stakeholder Materials
	(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the	7.3.1; 10.5.2; Technical Appendix Attachment 3.1 Stakeholder Materials

Rule Reference	Rule Description	Report Reference (Outline Section)
	discount rate specified.	
170 IAC 4-7-8 Cont.	(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.	2; 7; 8
	(8) Demonstrate, to the extent practicable and reasonable, that the preferred resource portfolio incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances quickly and appropriately. Unexpected changes include, but are not limited to, the following: See below. (A) The demand for electric service. (B) The cost of a new supply-side or demand-side technology. (C) Regulatory compliance requirements and costs. (D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	7; 8
170 IAC 4-7-9	**Short term action plan**	
	Sec. 9. A short term action plan shall be prepared as part of the utility's IRP, and shall cover each of the three (3) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. The short term action plan must include, but is not limited to, the following:	9

Rule Reference	Rule Description	Report Reference (Outline Section)
	(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) The implementation schedule for the preferred resource portfolio. (3) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (4) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	

List of Acronyms/Abbreviations

AAB	Advanced Automotive Batteries
ABB	AB Brown Generating Station
AC	Alternating Current
AUPC	Average Use Per Customer
B	Water Heating Service – Closed to new customers
BAGS	Broadway Avenue Generating Station
Bat	Battery
BES	Bulk Electric System
Bn	Billion
BNEF	Bloomberg New Energy Finance
BOS	Balance of System
BTMG	Behind The Meter Generation
Btu	British Thermal Unit
C&I	Commercial and Industrial
CAA	Clean Air Act
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CC	Combined Cycle
CC CT	Combined Cycle Combustion Turbine
CC ST	Combined Cycle Steam Turbine
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CEMAC	Clean Energy Manufacturing Analysis
CEMS	Continuous Emissions Monitoring System
CFL	Compact Fluorescent Lighting
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
Comm	Commercial
CPCN	Certificate of Public Need and Necessity
CPP	Clean Power Plan
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
DB	Deutsche Bank
DC	Direct Current
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control

List of Acronyms/Abbreviations (Cont.)

DOE	U.S. Department of Energy
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand Side Management
DSMA	Demand Side Management Adjustment
EEFC	Energy Efficiency Funding Component
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, measurement, and Verification
EOP	Emergency Operating Procedure
EPA	U.S. Environmental Protection Agency
EPC	Engineering Procurement and Construction
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	FB Culley Generating Station
FBC3	FB Culley Unit 3
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GE	General Electric
GPCM	Gas Pipeline Competition Model
GPS	Global Positioning System
GS	General Service
GT	Gas Turbine
GTM	Green Tech Media
GW	Gigawatt
GWh	Gigawatt Hour
H_2SO_4	Hydrochloric Acid
HAP	Hazardous Air Pollutants
HCl	Hydrochloric Acid
HDD	Heating Degree Days
Hg	Mercury
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HUM	Humidity

List of Acronyms/Abbreviations (Cont.)

I&M	Indiana Michigan Power
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
Ind	Industrial
IPL	Indianapolis Power and Light Company
IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lb	Pound
LBA	Load Balancing Area
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LIB	Lithium-ion Battery
Li-ion	Lithium-ion
LMP	Local Marginal Pricing
LMR	Load Modifying Resources
LMR	Load Management Receivers
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LP	Large Power
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MEP	Market Efficiency Project
MILP	Mixed Integer Linear Programming
MISO	Midcontinent Independent System Operator
MISO Tariff	Open Access Transmission, Energy, and Operating Reserve Markets Tariff
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MMWG	Multiregional Modeling Working Group
MPSC	Missouri Public Service Commission
MSA	Metropolitan Statistical Area

List of Acronyms/Abbreviations (Cont.)

MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standard
NAICS	North American Industry Classification System
NAPP	Northern Appalachia
NEGT	Northeast Gas Turbine
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data, and Analysis
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NW Council	Northwest Power and Conservation Council
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMS	Organization of MISO States
ORSANCO	Ohio River Valley Sanitation Commission
OSS	Off Season Service
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PI	Personal Income
PIRA	PIRA Energy Group
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PM	Particulate Matter
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRB	Powder River Basin
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSEG	Public Service Electric and Gas
PSIG	Pounds Per Square Inch Gauge
PTI PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PUC	Public Utility Commission
PV	Photovoltaic

List of Acronyms/Abbreviations (Cont.)

Res	Residential
RF	ReliabilityFirst
RGGI	Regional Greenhouse Gas Initiative
RIM	Ratepayer Impact Measure
RS	Residential Service
RTO	Regional Transmission Operator
SAE	Statistically Adjusted End-use
SB	Senate Bill
SBS	Sodium Bisulfite
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SD	Standard Deviation
SDE	Stochastic Differential Equation
SEA	Senate Enrolled Act
SEIA	Solar Energy Industries Association
SGS	Small General Service
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SIS	System Impact Study
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STD Dev	Standard Deviation
SVC	Static Var Compensator
T&D	Transmission and Distribution
TBtu	One Trillion British Thermal Unit
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
UE	University of Evansville
UPC	Use Per Customer
V	Volt
VAR	Volt-Amp Reactance
VEDO	Vectren Energy Delivery of Ohio
VOM	Variable Operation and Maintenance
VUHI	Vectren Utility Holdings Inc.
Wdc	Watt Direct Current
WN	Weather Normalized
WTE	Waste To Energy

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Executive Summary (Non-Technical Summary)

I. Introduction

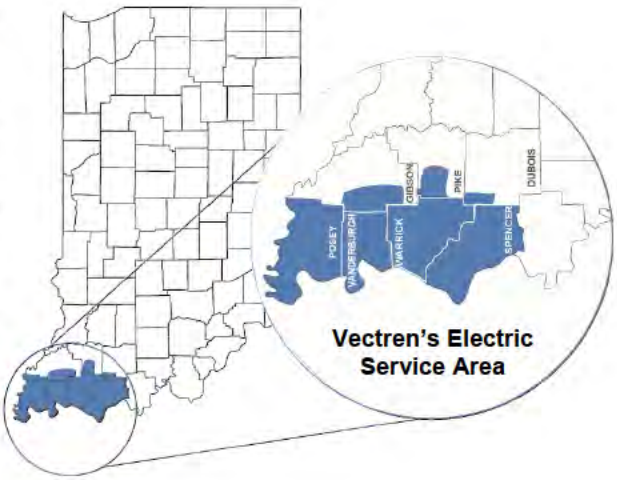
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren") engaged in a planning exercise during 2016 to evaluate its electric supply needs over a 20-year planning horizon. That exercise culminated in this 2016 Integrated Resource Plan ("IRP"). This planning exercise evaluated anticipated customer demand for electric supply in Vectren's electric service territory and identified resources to satisfy that demand. It included public meetings designed to solicit input from stakeholders about modeling assumptions. The evaluation then sought to use the inputs to estimate the total 20-year net present value cost, in 2016 dollars, of the various resource plan options to satisfy that demand. The analysis factored in the risk with heavy emphasis on evaluating the plan in the face of multiple possible future states. The future could bring various government regulations, varying fuel prices, varying resource costs, etc. This analysis was used to identify the portfolio of electric supply and demand side resources that best balances reliability, cost, risk, and sustainability.

Based on this planning process, Vectren has selected a preferred portfolio plan that balances the energy mix for its generation portfolio with the addition of a new combined cycle gas turbine facility and solar power plants and significantly reduces its reliance on coal-fired electric generation. Vectren's preferred portfolio reduces its cost of providing service to customers over the next 20 years by approximately $60 million as compared to continuing with its existing generation fleet. Additionally, the preferred portfolio reduces carbon dioxide output by approximately 46% by 2024 from 2012 levels, exceeding the Clean Power Plan (CPP) regulation, which requires a 32% reduction by 2030. When considering 2005 levels, this would be a reduction of almost 60%. Importantly, from a risk perspective, Vectren will continue to evaluate its preferred portfolio plan in future IRPs to ensure it remains the best option to meet customer needs.

What follows is a summary of the process Vectren engaged in to identify this portfolio, focusing on Vectren's operations, an explanation of the planning process, and a summary of the preferred portfolio.

II. Vectren Overview

Vectren provides energy delivery services to over 144,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. In 2015, approximately 50% of electric sales were made to large (primarily industrial) customers, 26% were made to residential customers and 24% were made to small commercial customers.



The table below shows Vectren Generating units. Note that Vectren also offers customers energy efficiency programs to help lower customer energy usage and bills.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit Age	Coal Unit Environmental Controls[1]
AB Brown 1	245	Coal	1979	Yes
AB Brown 2	245	Coal	1986	Yes
FB Culley 2	90	Coal	1966	Yes
FB Culley 3	270	Coal	1973	Yes
Warrick 4	150	Coal	1970	Yes
AB Brown 3	80	Gas	1991	
AB Brown 4	80	Gas	2002	
BAGS 2	65	Gas	1981	
Northeast 1&2	20	Gas	1963 / 1964	
Blackfoot[2]	3	Landfill Gas	2009	
Fowler Ridge	50	Wind PPA	2010	
Benton County	30	Wind PPA	2007	

[1] All coal units are controlled for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_X), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide (SO_3) except FB Culley 2.
[2] The Blackfoot landfill gas generator is connected at the distribution level.

III. Integrated Resource Plan

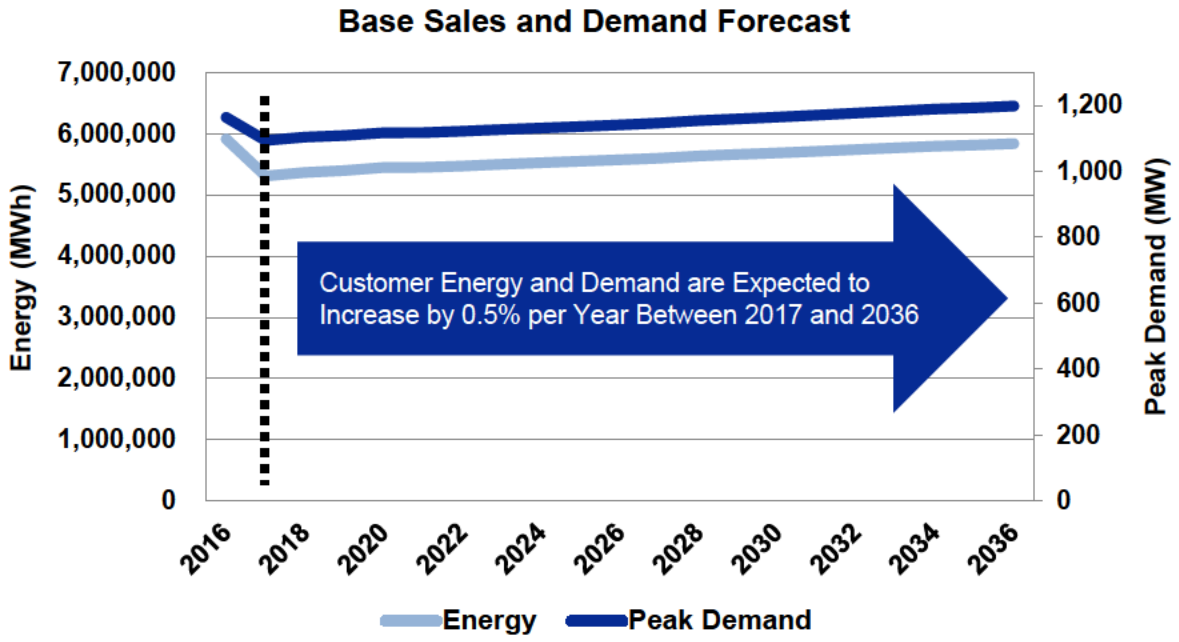
Vectren periodically submits IRPs to the Indiana Utility Regulatory Commission (IURC or Commission) as required by IURC rules. The IRP describes the analysis process used to determine the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, low cost, environmentally acceptable power over the next 20 years. The IRP can be thought of as a compass setting the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to finalize the detailed course.

Vectren considered input/perspectives from stakeholders, including but not limited to Vectren residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, environmental advocacy groups, and Vectren shareholders. Throughout the IRP analysis, Vectren placed an emphasis on reliability, customer cost, risk, and sustainability.

A. Customer Energy Needs

An IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. Vectren worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Energy is typically measured in Megawatt hours (MWh), and demand is typically measured in Megawatts. Both are important considerations in the IRP. While Vectren purchases some power from the market, Vectren is required to have enough generation and energy efficiency resources available to meet expected customers' annual peak demand plus additional reserve resources to help maintain reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO (Midcontinent Independent System Operator) member, Vectren must comply with MISO established reserve requirements.

Vectren utilizes sophisticated models to help determine energy needs for residential, commercial, and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, and weather. In 2017, a large customer is expected to commence generating a large portion of its energy needs with its own generation, which will decrease Vectren's overall energy and demand forecast between 2016 and 2017. Beyond 2017, these forecasts, which do not include future energy company sponsored energy efficiency, indicate that overall customer energy and demand are expected to grow by 0.5% per year.



B. Resource Options

The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. Vectren considered both new and existing resource options. Burns and McDonnell, a well-respected engineering firm, provided Vectren with detailed information on each of the generating resources, including but not limited to, capital costs, operating costs, operating characteristics, how much generation to expect under various conditions, plant emissions, etc. These costs provide a complete picture of the cost of various resource options over the entire 20-year period. Numerous costs impact supply resources, but the following that had a particularly significant impact on the IRP were EPA regulations, low natural gas prices, and renewable costs.



Energy Efficiency/Demand Response

Natural Gas, including CHP

Coal

Renewables, Wind & Solar

Battery Storage



Through investments in emissions control equipment over the past 15 years, Vectren's power system became one of the best controlled for emissions in the Midwest.

i. Environmental Protection Agency (EPA) Regulations

While Vectren's coal plants are controlled to meet or exceed current regulations for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), mercury, and particulate matter (dust), new EPA regulations require Vectren, and other utilities around the country, to make incremental investments in coal-fired generation plants if they are to continue operating them. The EPA regulation adoption process begins with a notice of proposed rulemaking, accepts comments from the public, and then finalizes rules for announcement. The EPA issued final rules for Effluent Limitations Guidelines (ELG) in 2015 (regulates water discharge)

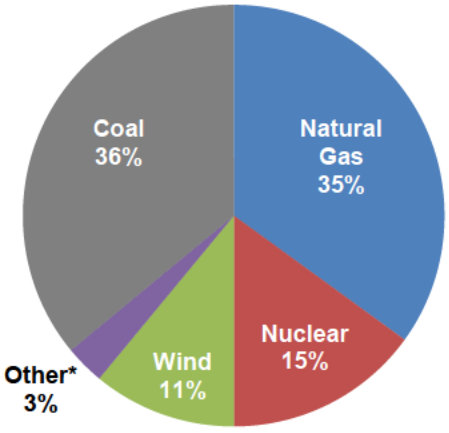
and Coal Combustion Residuals (CCR) in 2015 (regulates coal ash ponds) that were more stringent than first proposed. The Clean Power Plan (CPP), which regulates carbon dioxide emissions, would also impact the ability to cost-effectively operate coal-fired generation if it moves forward and is also more stringent than first proposed.

Each new regulation increases the cost of operating existing coal-fired plants over the 20-year horizon. Investment in Vectren's existing coal-fired generation to achieve compliance with ELG regulations would be significant. As currently written, ELG compliance would require investments by 2023.

ii. Low Gas Prices

The cost of fuel used by generation facilities to produce electricity is also accounted for in evaluating the cost of various electric supply alternatives. Gas prices are low and projected to be stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices, and is fueling a surge in low-cost gas generation around the country. Vectren's IRP reflects the benefit low gas prices provide to gas-fired generation.

Projected 2030 MISO Energy Mix



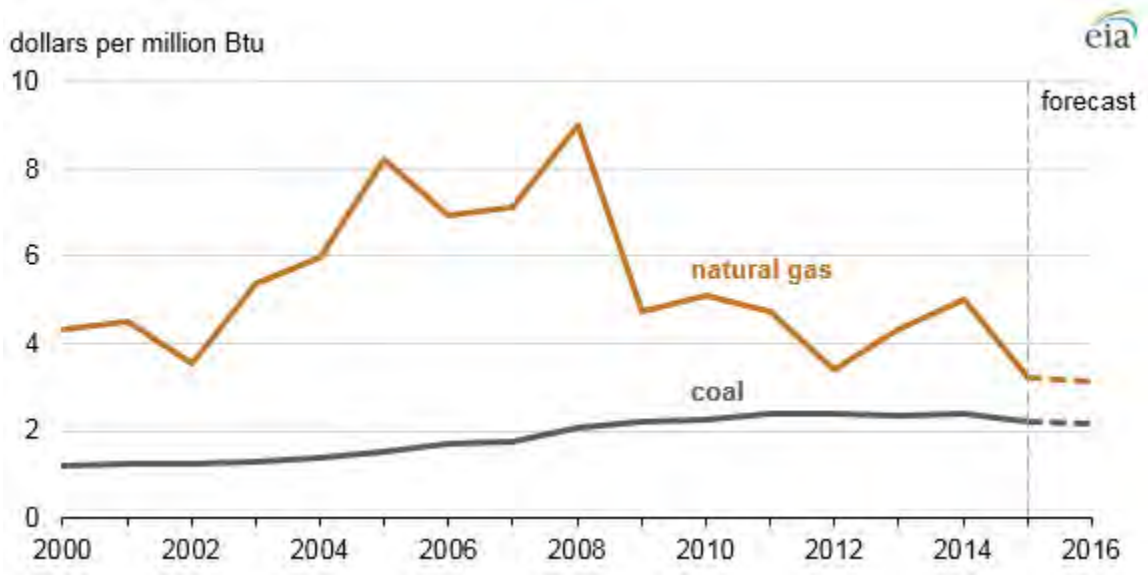
*Other includes hydro, pumped hydro, oil, solar, and others.

Vectren is a member of MISO, an independent transmission operator, which functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). Within the MISO footprint, energy from gas generation has increased from 17% of total electric generation in 2014 to 28% in 2016. Energy from gas generation is projected to grow to 35% by 2030[3].

[3] MISO, 2016 Winter Readiness Workshop, presented on October 31st 2016, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20

While the cost advantage of natural gas makes switching to natural gas-fired generation appear to be preferable from a cost perspective, Vectren also factored in the risk of particular supply side resources to its IRP. Reliance on an all natural gas generation portfolio would eliminate any resources that could mitigate the impacts of high gas prices or environmental regulations impacting natural gas facilities that might occur in the future. Vectren's risk modeling identified the risks with an unbalanced portfolio.

The table below shows average gas and coal fuel receipt costs at electric generating units between 2000 and 2016[4]. Note that shale gas has driven low gas costs since 2009.



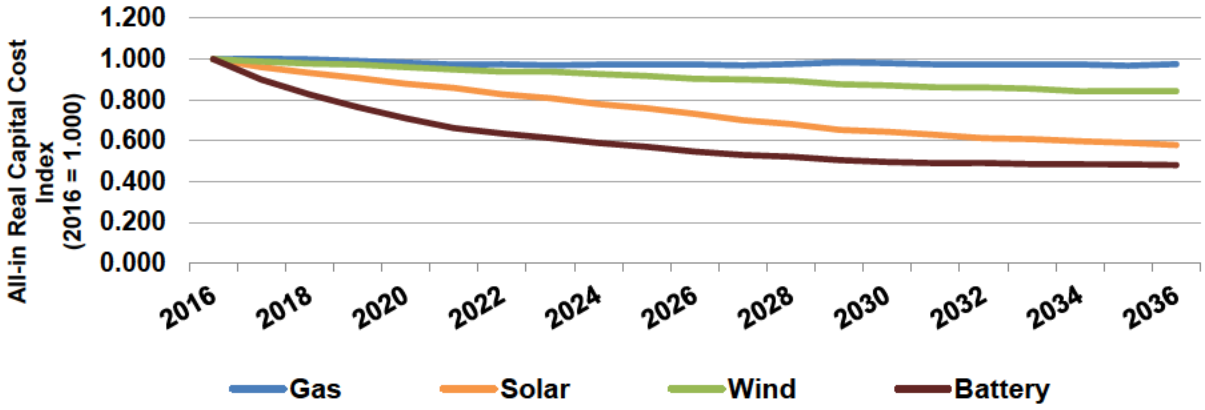
iii. Cost of Renewables

Another factor in Vectren's resource evaluation is the timing of the reduction in renewable energy costs. Vectren must either invest in its coal-fired generation to comply with ELG requirements, as currently written, or construct replacement generation by 2023. Renewable costs continue to decline, but they are still expected to

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[4] U.S. Energy Information Administration, *Electric Power Monthly*, and *Short-Term Energy Outlook* (March 2016); http://www.eia.gov/todayinenergy/detail.cfm?id=25392

be more expensive in the Midwest region than other alternatives in the next several years. Vectren needs to learn more about integrating solar resources in its territory, but the price decline and cost effectiveness of large renewable investments does not support a larger investment by Vectren based upon the timing for resource decisions. Advancements in technology should drive renewable and battery storage costs down over the next several years, making them more competitive with other generation resources. Pace Global, an industry expert consultant, helped develop cost curves based on industry projections as well as their expert judgment. The cost curves below were included in Vectren's IRP analysis.



C. Uncertainty/Risk

The future is far from certain. Uncertainty creates a risk that a generation portfolio that was reasonable under an anticipated future fails to perform as expected if the future turns out differently. Vectren's integrated resource plan analysis was developed to identify the best resource mix of generation and energy efficiency to serve customer energy needs over a wide range of possible future states. To help better understand the wide range of possibilities for regulations, technology breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with varying resource mixes.

IV. Analysis

Having identified its need for electricity and the potential resources to satisfy that need, Vectren conducted an analysis to identify a 20-year preferred resource plan. Vectren's 2016 IRP analysis was more robust than ever before. A methodical, step-by-step analysis was used to determine the preferred portfolio. Analysis steps are listed below.

1) Determined objectives in developing a preferred resource plan, including:
   a) Maintain reliability
   b) Minimize cost to customers
   c) Mitigate risk to customers and Vectren
   d) Provide environmentally acceptable power leading to a lower carbon future
   e) Include a balanced mix of energy resources
2) Worked with consultants and IRP stakeholders to anticipate future uncertainties and incorporate them into several possible future states of the world. The future could bring economic development, economic stagnation, increased pace of technological development, more regulations, or fewer regulations. Multiple possibilities were explored.
3) Utilized computer modeling to consider various resource combinations to meet customer energy needs in each of these possible futures. The model is a deterministic, optimization model. It considered thousands of possible resource combinations to satisfy customer demand and energy needs for each pre-determined future. The model optimizes on cost to the customer. Seven portfolios were created; one for each pre-determined future. While creating these computer-generated resource portfolios are an important step in resource planning, it is also important to use judgment to consider other possibilities in creating portfolios with a balanced mix of resources to meet customer energy needs.
4) Worked with external stakeholders that participated in Vectren's IRP public stakeholder meetings to develop two balanced portfolios. Vectren also worked with expert consultants to develop five additional balanced portfolios. Additionally, Vectren included a portfolio very similar to the current mix of resources, which is

heavily reliant on the five existing coal units. In all, 15 portfolios were created for analysis.

5) Utilized probabilistic modeling to simulate operating each of the 15 portfolios under 200 possible computer-generated futures. The model captured portfolio performance to determine likely portfolio operating costs, emissions of carbon dioxide and regulated pollutants, exposure to the energy markets, risk, etc. In essence, this resulted in 3,000 model runs.
6) Used a balanced scorecard approach to evaluate the potential impact of multiple risk factors on each portfolio, including but not limited to, customer cost, environmental impact, flexibility, balance of resources, and economic impact to the communities that Vectren serves. No single portfolio performed best in all categories; however, the preferred portfolio performed well in all measured risk contingencies.

V. Stakeholder Process

Vectren believes in the importance of stakeholder engagement. Vectren's objectives for stakeholder engagement are as follows:

- **Listen**: Understand concerns and objectives
- **Inform**: Increase stakeholder understanding of the Integrated Resource Plan process, key assumptions, and the challenges facing Vectren and the electric utility industry
- **Consider**: Provide a forum for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform Vectren's decision making

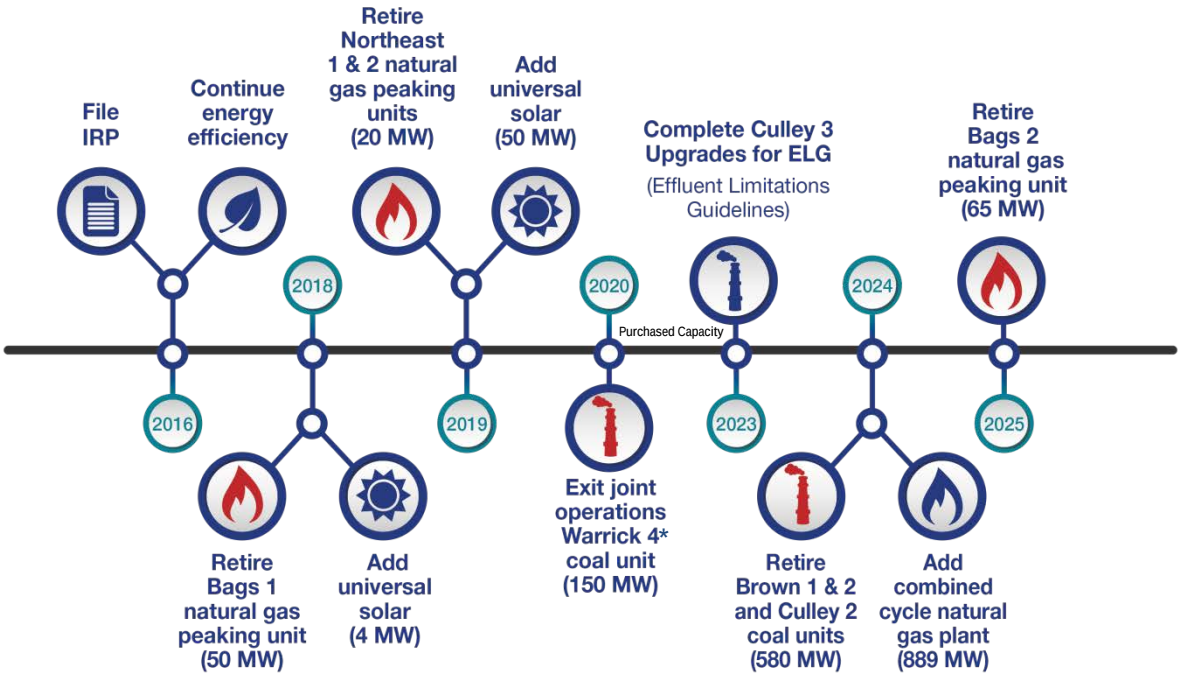
Vectren worked hard to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren stakeholder meeting was opened by Carl Chapman, Chairman, President, and Chief Executive Officer of Vectren. He and other senior management, Vectren subject matter experts, and expert consultants actively participated in each meeting to help address stakeholder questions/concerns. Additionally, Vectren addressed stakeholder questions outside of public meetings via irp@vectren.com in a timely manner.

On February 3, 2016 Vectren participated in the Joint Utilities Stakeholder Education Session with other Indiana investor-owned utilities. After that, Vectren hosted three public stakeholder meetings at its headquarters in Evansville, IN. Dates and topics covered are listed below:

- April 7, 2016 – Vectren Public IRP Stakeholder Meeting
  - Vectren IRP Process Overview
  - Gathered Stakeholder Input on Uncertainties
  - Long-term Energy and Demand Forecast
  - Customer-Owned Distributed Generation
  - 2016 IRP Technology Assessment Generation Resource Alternatives
  - Generation Retrofit Alternatives
  - Energy Efficiency Modeling Discussion
- July 22, 2016 – Vectren Public IRP Stakeholder Meeting
  - Environmental Compliance
  - Base Case/Modeling Inputs
  - Resource Screening Analysis and Optimization Modeling
  - Scenario Development
  - Gathered Stakeholder Input to Portfolio Selection
- November 29, 2016 – Vectren Public IRP Stakeholder Meeting
  - Recap of Vectren IRP analysis
  - Presentation of the Preferred Portfolio
  - Existing EPA Regulations
  - Optimization Modeling Results and Portfolio Development
  - Risk Analysis Results

In addition to these public meetings, Vectren met with the Vectren Oversight Board and staff from the Indiana Utility Regulatory Commission to discuss energy efficiency modeling for the 2016 IRP on October 14, 2016. All Vectren stakeholders were invited to participate via webinar.

VI. The Preferred Portfolio



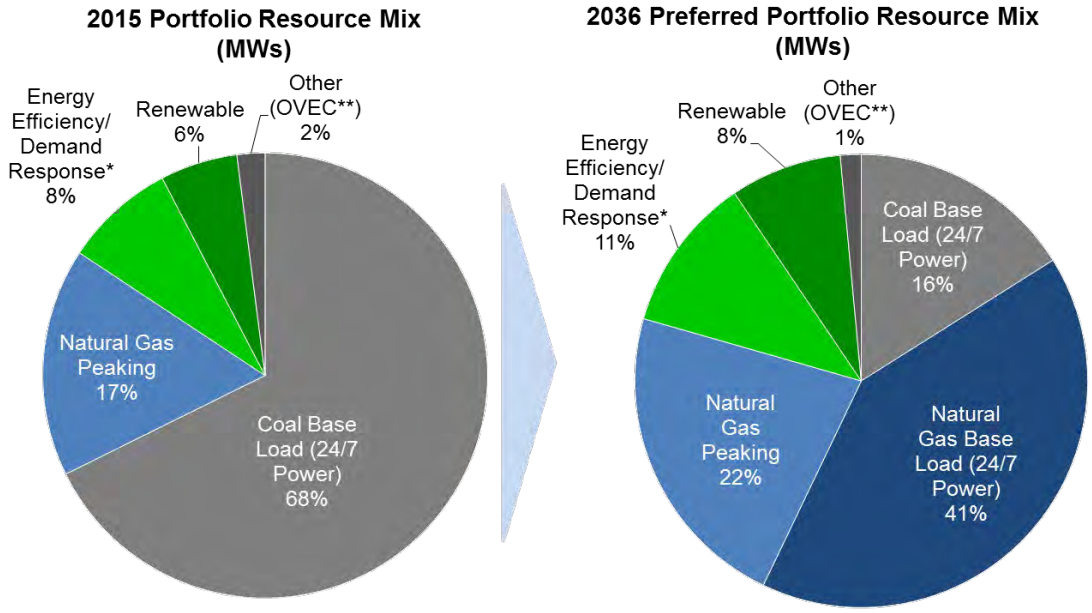
*Warrick 4 jointly owned with Alcoa, which is in the midst of transition. Vectren continues to discuss the future of Warrick 4 with Alcoa.

Based on the analysis Vectren conducted, Vectren has identified a preferred portfolio that consists of continued energy efficiency, retirement of existing coal and some gas units (Bags Units 1 and 2, Brown Units 1 and 2, FB Culley Unit 2, and Northeast Units 1 and 2), exiting joint operations of Warrick Unit 4, and construction of a combined cycle natural gas plant and solar generation. This preferred portfolio:

- Is among the best performing portfolios across multiple measures on the balanced scorecard.
- Is among the lower cost portfolios (within 4% of the lowest cost portfolio).
- Leads to a lower carbon future – Achieves almost 50% reduction in carbon (base year 2012) by 2024, which exceeds the Clean Power Plan (CPP) requirements – carbon emissions reduction from 2005 levels would be almost 60%.
- Brings renewables into the portfolio by 2019. Renewables and ongoing Energy Efficiency account for approximately 20% of total capacity by 2036.

- Provides low-cost peaking generation through duct-firing[5] that enhances opportunities for economic development and wholesale sales, which lowers customer bills.
- Avoids reliance on a single fuel and provides a balanced mix of coal, gas, and renewables. While reliance on gas is significant, a duct-fired plant would allow for back up of further variable renewable resources in the long term.
- Is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. University of Evansville professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately 7 million dollars annually. Moreover, to the extent a new gas unit is built at the AB Brown site, over 100 total jobs are expected to be retained in the community. Total state and local tax impact would be approximately 4 million dollars annually.
- Reduces dependence on coal-fired generation over time and provides flexibility to adapt to changes in technology.
- Takes advantage of tax incentives for solar power plants.

[5] Depending on set up, Duct-firing can provide approximately 200 MWs (Installed Capacity) of efficient peaking capacity capability through gas burners located within the heat recovery steam generator. These burners can be fired to generate more power when needed.



*Cumulative Demand Response & Net Energy Efficiency
**Vectren's 1.5% ownership of Ohio Valley Electric Corporation (OVEC) coal units. Per contractual obligations, all portfolios include OVEC.

VII. Next Steps

The preferred portfolio calls for Vectren to make changes to its generation fleet. Some of these changes require action in the near term. First, the IRP calls for continuation of energy efficiency. Vectren's current authority related to energy efficiency initiatives expires on December 31, 2017. Vectren will file for authority necessary to facilitate continuation of energy efficiency early in 2017 so that programs continue to be available. Second, Vectren must comply with ELG requirements, as currently written, by the end of 2023. As such, Vectren plans plant upgrades for FB Culley 3 for conversion of dry bottom ash and flue gas desulfurization waste treatment. The preferred portfolio calls for construction of a new combined cycle gas turbine in lieu of further investments in Brown Units 1 and 2, FB Culley Unit 2, and Warrick Unit 4 to ensure compliance. IURC approvals will need to be sought in the near future. Third, Vectren intends to pursue solar projects in 2017 and 2019. These filings will be consistent with the preferred portfolio. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in

commodities, regulations, political policies, and other assumptions could warrant deviations from the preferred plan.

Following the outcome of the recent presidential election, there is potential for industry change over the next several years. For example, the EPA's Clean Power Plan may be rescinded or modified. Additionally, Clean-Energy Tax incentives may be at risk. Even in the midst of possible industry change, other rules like ELG/CCR, which are the main drivers of closing Vectren coal plants, will be much more difficult to change.

Vectren is confident in the need for new gas generation in 2024. Under all scenario modeling, a natural gas-fired plant was selected, including the low regulatory scenario. While future carbon regulations are less certain than prior to the election, it is likely that new administrations will continue to pursue a long term lower carbon future. Vectren's preferred portfolio positions the company to meet that expectation.

Other aspects of the preferred portfolio are less certain. For example, the timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa, which recently went through a corporate reorganization and remains in the midst of transition. Given the plant, absent incremental investment, does not comply with the CCR and ELG requirement, Vectren continues to talk to Alcoa about the timing of possible closure. Additionally, Vectren plans to add 50 MW of solar in 2019, which corresponds with clean energy tax incentives. Timing of this solar plant may change should these incentives not be available.

SECTION 1
OVERVIEW

1.1 COMPANY BACKGROUND

Vectren Corporation is an energy holding company headquartered in Evansville, Indiana. Vectren's wholly owned subsidiary, Vectren Utility Holdings, Inc. (VUHI), is the parent company for three operating utilities: Indiana Gas Company, Inc. (Vectren North), Southern Indiana Gas and Electric Company (Vectren), and Vectren Energy Delivery of Ohio (VEDO).

Vectren North provides energy delivery services to more than 570,000 natural gas customers located in Central and Southern Indiana. Vectren provides energy delivery services to over 144,000 electric customers and approximately 110,000 gas customers located near Evansville in Southwestern Indiana. VEDO provides energy delivery services to approximately 312,000 natural gas customers near Dayton in West Central Ohio.

1.2 INTEGRATED RESOURCE PLANNING

Vectren takes integrated resource planning very seriously. Vectren is required to submit its Integrated Resource Plan (IRP) to the Indiana Utility Regulatory Commission (IURC) every two years (moving to a three year cycle). The IRP begins with a forecast of customer electric needs over a 20-year period and is used as a guide for how Vectren will serve existing and future customers in a reliable and economic manner. The integrated resource plan can be thought of as a compass setting the direction for future generation and demand side management (DSM) options. It is not a turn-by-turn GPS. Future analyses of changing conditions, filings, and subsequent approvals from the IURC are needed to chart the specific course.

The future is uncertain. Several factors have helped to set the stage for this analysis. Environmental Protection Agency (EPA) regulations are putting great pressure on coal resources. Several regulations that were recently finalized are more stringent than originally proposed. Gas prices are low and projected to be stable over the long term.

Shale gas has revolutionized the industry, driving these low gas prices. This has fueled a surge in gas generation investment.

Renewable costs continue to decline, but they are still expected to be more expensive in the Midwest region than other alternatives in the next several years. Vectren will continue to monitor developments related to the high voltage transmission lines still needed to both increase the availability and reduce the cost of wind. Additionally, Vectren will continue to observe developments in Midcontinent Independent System Operator (MISO), Vectren's regional transmission operator. Within Vectren's zone, MISO is projecting a shortfall in generation and demand side options needed to maintain reliability beginning in 2018 for high certainty resources[6]. The shortfall continues to grow through 2021. Regardless of the final plan, reliability needs to be maintained, and customer costs must be a priority.

1.2.1 IRP Objectives

Vectren's IRP objectives are based on the need for a resource strategy that provides value to its customers, communities, and shareholders. Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the competitive and regulated markets. The main objective is to select a preferred portfolio[7] of supply and demand resources to best meet customers' needs for reliable, reasonably priced, environmentally acceptable power over a wide range of future market and regulatory conditions taking into account risk and uncertainty. Specifically, Vectren's objectives are as follows:

- Maintain reliability
- Minimize rate/cost to customers
- Mitigate risk to Vectren customers and shareholders
- Provide environmentally acceptable power leading to a lower carbon future

[6] High certainty resources are existing resources that have a "High" confidence of being available in the planning year, as determined by utilities in the Organization of MISO States (OMS) survey.
[7] A portfolio is a mix of future supply and demand side resources to meet expected future demand for electricity.

- Include a balanced mix of energy resources
- Minimize negative economic impact to the communities that Vectren serves

1.2.2 IRP Development

Since conducting the 2014 IRP, Vectren has worked diligently to incorporate stakeholder input (direct comments about the 2014 IRP, including the director's report, and indirect comments through suggestions to other utilities) into the 2016 analysis. As a result, the 2016 IRP is much more robust than any Vectren IRP before it.

Vectren made the following commitments, which are incorporated into this IRP analysis:

- construct scenarios (possible future states), which include coordinated data inputs with a well-reasoned narrative,
- conduct a probabilistic risk analysis to explore the outer bounds of probability,
- model future energy company sponsored energy efficiency as a resource (not built into the load forecast),
- evaluate if retirement makes sense for any of Vectren's existing coal generating units within the 20 year time frame under each scenario,
- monitor Combined Heat and Power (CHP) developments and include CHP as a resource option,
- consider conversion or repower of coal units to gas,
- fully consider renewable options, and
- update the IRP document format to be more readable.

Vectren worked closely with industry experts to develop a comprehensive analysis. Pace Global helped with scenario development, modeling inputs, and a comprehensive risk analysis, which included probabilistic modeling. Burns and McDonnell developed a technology assessment which provides resource costs for various types of generation technologies, such as gas, solar, wind, storage, etc. It can be found in Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table. Vectren also engaged Burns and McDonnell in developing a site selection

analysis to better understand the ideal location for gas generation, should it be chosen in the preferred portfolio. Additionally, Burns and McDonnell conducted a portfolio screening analysis to help determine the preferred portfolio. Itron developed the base sales and demand forecast, which included a forecast of customer owned solar generation.

1.3 CHANGES THAT HAVE OCCURRED SINCE THE LAST IRP

Several developments have occurred since the last IRP was submitted in 2014, which helps to illustrate the dynamic nature of integrated resource planning. The IRP analysis and subsequent write up represent the best available information for a point in time. The following sections discuss some of the major changes that have occurred over the last two years. The robust risk analysis recognizes that conditions will change. Changes over the last few years provided Vectren with valuable insight on how modeled scenario outcomes can change over time.

1.3.1 Environmental Rules

1.3.1.1 Air

There have been a number of changes in air regulations since the 2014 IRP. The Mercury and Air Toxics Standard (MATS) was published in the Federal Register in February 2012. The rule sets plant-wide emission limits for the following hazardous air pollutants (HAPs): mercury, non-mercury HAPs (e.g. arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride)[8]. Compliance with the new limits was required by April 16, 2015. At the time of the last IRP, Vectren was awaiting approval by the Commission for its MATS Compliance plan (IURC Cause 44446) which included organosulfide injection at the base load units (AB Brown 1, AB Brown 2, FB Culley 3, and Warrick 4). All equipment

[8] MATS Limits: The EPA established stringent plant-wide mercury emission limits (1.2 lb/TBtu for individual unit or 1.0 lb/TBtu for plant average) and set surrogate limits for non-mercury HAPs (total particulate matter limit of .03 lb/MMBtu) and acid gases (HCL limit of .002 lb/MMBtu). The surrogate limits can be used instead of individual limits for each HAP.

has been approved and installed, and Vectren's units are currently in compliance with MATS limits.

In March 2015, EPA entered into a Consent Decree[9] with environmental stakeholders to resolve litigation concerning deadlines for completing 1-hour sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS) designations. EPA identified five sources in Indiana that exceeded a set threshold for SO_2, including the AB Brown plant. In order to ensure that Posey County continued to meet the attainment designation for the new one hour standard, Vectren voluntarily agreed to lower its emission rate for SO_2 at its AB Brown plant. Vectren requested a Commissioner's Order to voluntarily accept a lower SO_2 emission limit that went into effect April 19, 2016. The state will continue to review modeling for additional counties including Warrick County and the FB Culley and Warrick power plants located within that county. A preliminary review indicates that Warrick County is in compliance without additional reductions.

In December 2015, Vectren agreed to a modified Consent Decree to resolve alleged air violations at the FB Culley and AB Brown plants. Based on the negotiated settlement, Vectren eliminated the bypass stack for FB Culley Unit 2 and installed equipment to mitigate incremental sulfur trioxide (SO_3) emissions from the selective catalytic reduction technology installed on AB Brown Units 1 and 2 and FB Culley Unit 3 to control nitrogen oxides (NOx). Each unit is required to maintain a sulfuric acid (H_2SO_4) emission limit to demonstrate compliance.

EPA finalized the Clean Power Plan (CPP) that established carbon dioxide (CO_2) emission standards for a state's electric generating fleet in August 2015. States were given the discretion to set unit specific limits or adopt a mass-based or rate-based allowance trading program. The US Supreme Court issued a stay of the rule, which will remain in place through ultimate Supreme Court review of the opinion of the lower court.

[9] The Consent Decree required EPA to designate as nonattainment, attainment, or unclassifiable certain areas that included sources that emitted more than 16,000 tons of SO_2 in 2012 or emitted more than 2,600 tons of SO_2 with an average emission rate greater than 0.45 lbs/MMBtu.

It is not anticipated that final order on judicial review will come until late 2017 at the earliest. In the event that the CPP is upheld, the state of Indiana will likely develop a State Implementation Plan (SIP). For this analysis, Vectren assumed a two year delay with compliance beginning in 2024.

In addition to the above regulations, on September 7, 2016, EPA finalized the Cross State Air Pollution Rule (CSAPR) Update Rule which established lower ozone season Nitrous Oxide (NOx) allowances for each unit to incorporate the revised Ozone NAAQS. The new limits take effect with the ozone season beginning in May 2017.

1.3.1.2 Water

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology based limits for waste water generated from fossil fuel fired generating facilities and in particular, will force significant operational and technological changes at coal-fired power plants. In the draft proposal, EPA listed eight possible options, with four identified as "preferred." Within the group of preferred options were exemptions for smaller scrubbers and generating units that could have exempted Vectren's units from certain requirements. However, in the final regulation EPA chose to bypass the preferred options and went with a hybrid of the most stringent options for fly ash transport water, bottom ash transport water, and flue-gas desulfurization (FGD) waste water.

While the final rule includes reference to multiple waste waters, the key elements applicable to Vectren are FGD waste water and ash transport water. Specifically, FGD waste water must meet new limits for arsenic, mercury, selenium, and nitrate at the end of the wastewater treatment system and prior to mixing with any other process water. Water used to transport bottom ash or fly ash is prohibited from discharge in any quantity which effectively forces the installation of dry or closed loop ash handling systems. The applicability date for the new requirements shall be as soon as possible after November 1, 2018 but no later than December 31, 2023 and established in a

schedule outlined in National Pollutant Discharge Elimination System (NPDES) permit renewals. For FGD waste water, alternate, but more restrictive limits can be voluntarily agreed to which would automatically extend the applicability date to December 31, 2023. Technology to meet the more restrictive limits could include the installation of zero liquid discharge equipment that would eliminate all discharge of FGD waste water.

1.3.1.3 Waste

The Coal Combustion Residuals Rule (CCR) was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards. The regulatory deadlines that could trigger the closure of surface impoundments include non-compliance with safety factor assessment standards (April 2017), exceedance of ground water protection standards (April 2018), or failure to demonstrate compliance with location restrictions (April 2019).

1.3.1.4 Post-election Regulations Update

President-elect Trump has indicated that he intends to review environmental regulations. However, at this time it is unclear which regulations President-elect Trump's new EPA administrator intends to review, other than the Clean Power Plan and the Waters of the US rule. In order to rescind and/or modify a final regulation such as the CPP, or the CCR and ELG rules, the new administration would be required to go through a new notice and comment rulemaking process, which could require 18 months to 2 years to complete, and in the case of health and / or technology based standards such as the ELG rule would require a defensible rationale.

With respect to the issue of carbon regulations, President-elect Trump could withdraw from the non-binding Paris carbon reduction goals. However, as indicated above, the

CPP is a final regulation, so it must be rescinded/modified through a supplemental notice and comment rulemaking. Additionally, the previous Endangerment Finding would also need to be rescinded and/or modified. It should also be noted the new Department of Justice may choose to no longer defend the rule; however, the rule would still be defended by some states and environmental groups. While these options are possible, all would require some time. The IRP is a long-term resource plan; future administrations will likely pursue a lower carbon future.

Even if the Trump administration successfully delays/rescinds the CPP, Vectren's decision on continuing operation of its coal-fired fleet is more heavily influenced by the CCR and ELG rules, the primary driver of near-term environmental compliance expenditures modeled in the IRP. These rules require notice and comment rulemaking to rescind and/or modify, which is an 18-24 month process. Rules such as the ELG rule are technology mandates arising under legislation, in this case the Clean Water Act, and are more difficult to set aside. They must be supported by a technological or human health rationale.

1.3.2 Environmental Upgrades for MATS

To comply with the Mercury and Air Toxics Standard (MATS), Vectren installed equipment to inject an organo-sulfide solution into the scrubbers at AB Brown Units 1 and 2, FB Culley combined stack for Units 2 and 3, and Warrick Unit 4. In addition to the treatment technology, MATS also required the installation of new monitoring equipment on the stacks for each of the listed units to assess compliance with the new limits. Continuous emissions monitoring system (CEMS) was installed to monitor filterable particulate (as a surrogate for non-mercury HAPS metals), a separate CEMS to monitor hydrogen chloride, and sorbent traps to measure mercury.

1.3.3 Legislation and IRP Rule Making Process

The Demand Side Management ("DSM") landscape in Indiana has undergone significant changes in recent years, beginning in 2014 with the enactment of Senate

Enrolled Act 340 ("SEA 340"). This not only allowed certain large Commercial & Industrial (C&I) customers to opt-out of participation in Company sponsored energy efficiency ("EE") programs, but also eliminated the savings targets for jurisdictional electric utilities established by the Commission in Cause No. 42396 ("Phase II Order").

Since then, Senate Enrolled Act 412 ("SEA 412") was codified at Ind. Code § 8-1-8.5-10 ("Section 10"), and further impacts how utilities plan for and implement EE programs in Indiana. Beginning not later than calendar year 2017, an electricity supplier, which includes Vectren, is required to petition the Commission at least one time every three years for approval of a plan that includes: (1) energy efficiency goals; (2) energy efficiency programs to achieve the energy efficiency goals; (3) program budgets and program costs; and (4) evaluation, measurement, and verification ("EM&V") procedures that must include independent EM&V (the "Plan").

Once a Plan has been submitted for approval, the Commission must consider the ten factors outlined in Section 10 when determining the overall reasonableness of the Plan. One of the factors that must be considered in this determination is whether the Plan is consistent with the electricity supplier's most recent long range IRP submitted to the Commission. Section 10 requires the Commission to approve an electricity supplier's Plan if, after notice, hearing, and consideration of the ten factors outlined in Section 10, the Commission determines the plan to be reasonable.

Besides the enactment of Section 10, another regulatory development is the pending rulemaking currently underway, known as IURC RM #15-06 that continues to refine the IURC's IRP rules. This is essentially a continuation of the rulemaking from IURC RM #11-07 that resulted in a draft rule dated October 4, 2012, which was never finalized and adopted by the Commission. However, Vectren and other utilities began voluntarily following the 2012 [IRP] draft rule in 2013 and 2014, which outlines the requirements for the IRP process and the IRP report. In crafting the proposed rule, the Commission began with the 2012 draft rule and accepted comments and edits to that draft rule. One

significant change from the 2012 draft rule to the proposed rule is the switch from a two year filing requirement to a three year filing requirement, which matches the three year EE Plan filing requirement set forth in Section 10. Vectren continues to actively participate in the rulemaking process and will be prepared to follow the rule once it is finalized and adopted by the Commission. Note that Vectren followed the 2012 draft rule for the 2016 IRP.

1.3.4 Alcoa

In January of this year, Alcoa announced it would permanently cease production of its Warrick Operation smelter in the 1st quarter. Alcoa also communicated that the on-site rolling mill and power plant will continue to operate.

The Warrick power plant consists of four generating units: three 150 Megawatt (MW) industrial units wholly owned by Alcoa and one 300 MW electric generating unit (Warrick 4) that is jointly owned by 50% Alcoa and 50% Vectren. Prior to the smelter closing, the Alcoa power plant provided most of its 600 MW electric generation, if not all, to meet the electric demand of the Warrick Operations facility with the smelter being the majority of that demand. With the smelter closing on March 24, 2016, the electric demand for the Warrick Operations facility is dramatically less. Alcoa has recently split into two (2) separate public companies. Given these operational and organizational changes, Alcoa's interest in continuing to operate the jointly owned Warrick 4 300 MW electric generating unit is unclear.

1.3.5 Co-generation (Combined Heat and Power)

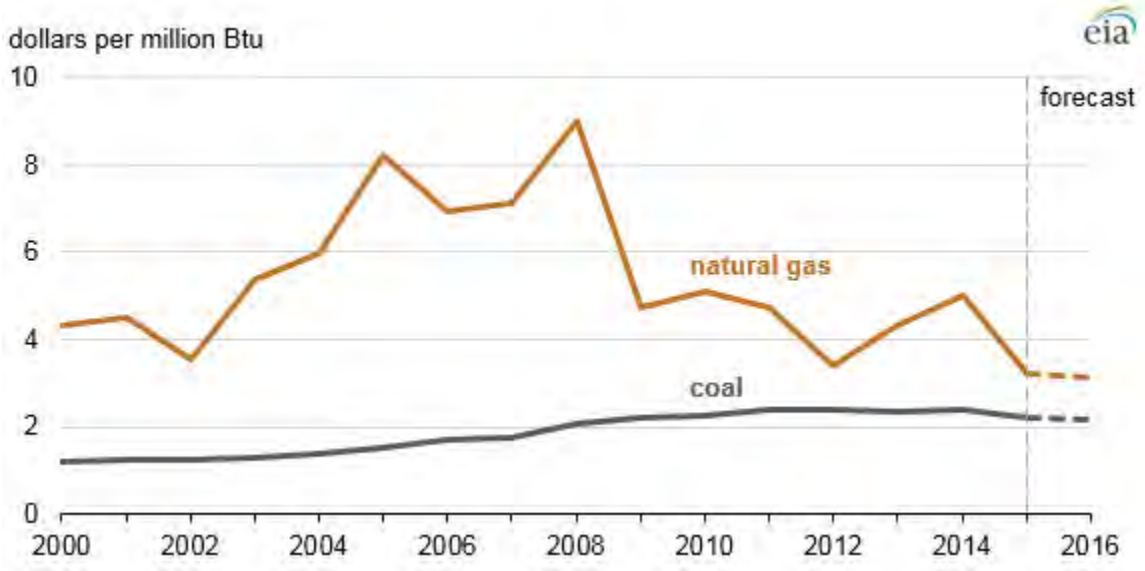
A large industrial customer has installed a natural gas fired co-generation unit that is expected to come on-line by January 2017. The co-generation unit is expected to cover the majority of this customer's load, and Vectren will cover the balance with firm service. The co-generation unit will produce steam and electricity for production processes. This development is reflected in the sales and demand forecast for the IRP.

1.3.6 Increasing Use of Gas-Fired Generation, Regionally and Nationally

There has been a surge of natural gas generation in the United States over the last several years. According to the EIA, electricity net generation from natural gas in the US has increased from approximately 14% in 2000 to approximately 32% in 2015[10]. This has been driven by three primary factors 1) low gas prices, 2) age of existing coal fired generation, and 3) stricter environmental requirements imposed on coal fired generation.

Gas prices are low and projected to remain stable over the long term. Shale gas has revolutionized the industry, driving gas prices down to historically low levels as the supply of natural gas has grown. In recent years, natural gas generation has been competitive with coal generation and therefore has frequently been economically dispatched in place of coal. The table below shows average gas and coal fuel receipt costs at electric generating units between 2000 and 2016[11].

Figure 1.1 – Average Fuel Receipt Costs at Electric Generating Plants (2000-2016)



[10] US Energy Information Administration; August 2016 Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector; http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf
[11] U.S. Energy Information Administration, *Electric Power Monthly*, and *Short-Term Energy Outlook* (March 2016); http://www.eia.gov/todayinenergy/detail.cfm?id=25392

Coal has been a long standing fuel for electric generation in the US, as a result a substantial portion of the existing coal fleet is reaching the age when wear and tear, and equipment obsolescence has made their continued operation uneconomic in the long run. Consequently a very sizeable portion of the US coal fleet has, or is expected, to retire due to old age.

In addition, as mentioned in Section 1.3.1, numerous environmental rules have been recently finalized by the EPA, including MATS, ELG, CCR, and CPP. Collectively these rules have helped to retire coal plants across the country, with more closures to come through the early 2020s due to associated compliance costs. Additionally, some politicians and environmental advocacy groups have worked hard to negatively shape public perception of coal fired power plants. Government support for renewables in the form of tax incentives and renewables portfolio standards have also helped to displace coal generation in the market.

1.3.7 MISO

MISO requires Vectren and other member electric utilities to maintain a Planning Reserve Margin (PRM). The PRM is designed to ensure there is enough power capacity throughout the MISO region to meet customer demands during peak periods, including peak periods where some equipment might fail. In recent years, the Planning Reserve Margin (PRM) throughout MISO has dwindled. Because there is less availability of capacity, the price for capacity available in MISO's annual auction has been volatile. The Organization of MISO States (OMS), of which the IURC is a participant, and MISO teamed together to better understand future resource needs. Since June of 2014, MISO and the OMS have compiled Resource Adequacy survey responses from MISO members that indicate the need for more supply and demand side resources to meet expected load. This survey has served as the main vehicle in communicating to the MISO stakeholder community the anticipated PRM for upcoming years and serves as a tool in determining whether additional action is needed.

Since its inaugural survey, MISO has warned that there may be inadequate capacity within the MISO footprint at some future date. OMS-MISO Resource Adequacy survey results have shown projected shortfalls for high certainty resources in the MISO region and Zone 6, which includes most of Indiana and a small portion of Kentucky. The table below illustrates the year-to-year volatility in the survey results and the uncertainty that exists.

Figure 1.2 – OMS-MISO Resource Adequacy Survey Results

OMS-MISO Resource Adequacy Survey Results by Year	Zone 6 Resource Adequacy Shortfall, Earliest Projection	MISO-wide Resource Adequacy Shortfall, Earliest Projection
2014	1.2 GW shortfall in 2016	2.0 GW shortfall in 2016
2015	400 MW shortfall in 2016	1.8 GW shortfall in 2018
2016	800 MW shortfall in 2018	400 MW shortfall in 2018

The projected capacity shortfalls have contributed to volatile capacity prices. MISO's Planning Resource Auction (PRA) is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013[12], as shown in the table below. These large swings in prices have made it difficult to forecast forward years.

[12] SNL Financial – Market Prices – ISO Capacity Summary – MISO

Figure 1.3 – MISO Zone 6 Capacity Price History

Planning Year	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/day[13]	Clearing Price for Zone 6 (Indiana & Kentucky) per MW/year	Year-over-Year Price Change
2013-2014	$1.05	$383.25	-
2014-2015	$16.75	$6,113.75	1495% Increase
2015-2016	$3.48	$1,270.20	79% Decrease
2016-2017	$72.00	$26,280.00	1969% Increase

MISO has stated that its role in resource planning is to provide data transparency, markets signals, and assist its stakeholders throughout the resource planning process. To improve its market signals, MISO is currently working on several reforms to its capacity construct. Additionally, in order to ensure data transparency and assist its stakeholders in resource planning, MISO is working with the OMS to refine the results from the survey and continue improving the accuracy and metrics in which the PRM is measured. For more information on MISO, please read Section 4.7, PLANNING RESERVE MARGIN DISCUSSION.

1.3.8 Solar Generation

The Energy Policy Act of 2005 created a 30 percent ITC for residential and commercial solar energy systems placed in service between January 1, 2006 and December 31, 2007. The in service date has been extended several times since then, most recently in 2015 in the Omnibus Appropriations Act (P.L. 114-113). Additionally, the language was updated from "in service" to "commence construction" for projects completed by the end of 2023. 2019 is the last year to commence construction and receive the full 30% benefit (it tapers down from there).

Renewable costs, particularly solar, continue to decline helping to drive demand for more solar energy production. Even with the extension of the ITC, solar panel energy in

[13] MW/day is the amount customers are required to pay should they purchase capacity via the MISO Planning Resource Auction. For example in the 2016-2017 planning year each MW cost $72 per day ($26,280 per MW annually).

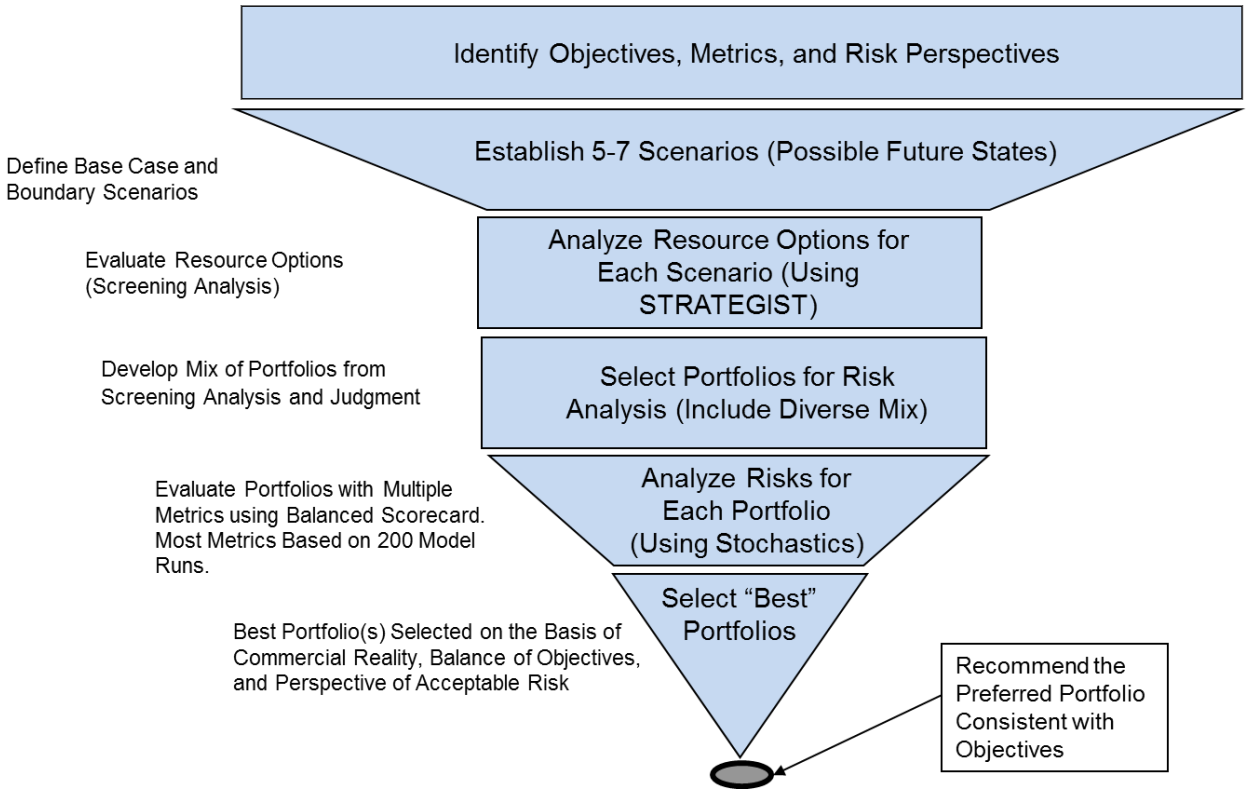
the Midwest is still expected to be more expensive than other alternatives in the next several years. In 2015, solar energy accounted for 1% of total generation in the U.S.

SECTION 2
VECTREN'S IRP PROCESS

2.1 VECTREN'S IRP PROCESS

Vectren's 2016 IRP followed a very structured, comprehensive process over a 15 month period with extensive economic, technical, and risk analyses. This process was designed to ensure that all relevant technologies were screened and evaluated, and the resulting portfolio combinations were subjected to a wide range of future market and regulatory conditions to ensure that the recommended portfolio would best meet its objectives under uncertainty. The process followed is illustrated below.

Figure 2.1 – Vectren IRP Process



The process used to select the recommended portfolio is outlined below:

- Section 2.2 describes how multiple objectives were tracked and measured. These metrics were the key to evaluating how portfolios were judged against each other in the final selection of the best portfolio.

- Section 2.3 describes how the scenarios were developed for screening technologies. Vectren selected six "boundary scenarios" around its consensus base case scenario to ensure that the portfolios selected perform reasonably well across a range of market and regulatory conditions.
- Section 2.4 describes the screening of technologies. Burns and McDonnell used the STRATEGIST model to assess how different technologies and groups of technologies performed across each of the base case and six additional scenarios to help Vectren define which portfolios it wanted to consider for its risk analysis.
- Section 2.5 describes the selection of a group of portfolios for risk analysis. Some of the portfolios came directly out of the screening analysis, considering which group of portfolios performed best under each set of market and regulatory conditions. Others were selected based on the judgment of Vectren and by stakeholders through its stakeholder process. Vectren wanted to ensure that there was due consideration to metrics besides least cost to capture more diverse portfolios, greater penetration of renewables, energy efficiency, and other considerations.
- Section 2.6 describes the input distributions for the risk analysis. This tracks the steps performed in the process, the selection of the distributions, and the use of AURORAxmp to provide carbon prices, power prices, and market retirements and construction of new generation. This section also describes the analysis of the portfolios against the 200 iterations of scenarios that were developed in the previous steps and how resulting metrics are evaluated.
- Section 2.7 describes the selection of the "best" portfolio and provides the basis for eliminating portfolios that do not perform well against target metrics and for selection of a portfolio that performed best.

Vectren evaluated and balanced the expected costs and risks of each portfolio, incorporating environmental goals, to select a portfolio with a good cost-risk combination. Throughout the process, Vectren sought and received input from

stakeholders through three public meetings meant to educate and engage all those with an interest in this IRP.

2.2 IDENTIFY OBJECTIVES, METRICS, AND RISK PERSPECTIVES

Vectren's IRP process is designed to assure a systematic and comprehensive planning process to determine the "recommended portfolio" that best meets all of its objectives over a wide range of market futures. This process results in a reliable and efficient approach to securing future resources to meet the energy needs of the energy company and its customers.

In addition, the IRP process ensures that Vectren meets its environmental regulations and reliability requirements, while reducing its vulnerability to market and regulatory risks, the risk of supply disruptions, and increases the diversification of its supply sources, maintaining the flexibility to take advantage of renewable options and storage when the economic conditions favor it.

One component of resource planning is "least cost" planning, which identifies the portfolio or supply and demand resources that are most likely to result in the lowest expected cost to its customers. While this is certainly an important objective, it is by no means the only objective. Vectren has a number of important objectives, each of which needs to be considered when evaluating the best portfolio for its stakeholders over time. Vectren's IRP strategy is designed to accommodate the ongoing changes and uncertainties in the market. Vectren's IRP objectives are based on the need for a resource strategy that provides long term value to its customers, communities, and shareholders. Specifically, Vectren's IRP objectives are as follows:

- Provide all customers with a reliable supply of energy at the lowest reasonable cost.
- Develop a plan with the flexibility to adapt to market conditions, regulatory and technological change to minimize risk to Vectren customers and shareholders
- Provide environmentally acceptable power, leading to a lower carbon future

- Provide a predictable, balanced mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
- Minimize the impact of Vectren's past, current, and future operations on the local economy.
- Provide high-quality, customer-oriented services which enhance customer value.

Each objective was given defined and measurable metrics. By testing alternative portfolios against these metrics, Vectren increases the likelihood that the portfolio it ultimately selects will be the best portfolio, in that it meets all of Vectren's objectives better than any other portfolio of assets across a broad range of possible futures. The following metrics were used to select the preferred portfolio:

Figure 2.2 – Vectren Risk Metrics

Objective	Metric
Customer Rate (or utility cost) Metric	• Net Present Value (NPV) of Revenue Requirements
Manage or Minimize Market Risks	• Standard Deviation of NPV Across 200 Future Conditions • Volume of Market Purchases • Volume of Capacity Purchases
Cost Risk-Tradeoff	• NPV against Standard Deviation
Balance and Flexibility	• Net Sales Position • Concentration on One Technology • Number of Technologies • New Remote Resources in Generation Mix
Environmental Requirements	• CO_2 Reductions from 2012 levels • SO_2 and NO_X Reductions from 2012-2015 levels
Local Economic Impacts	• Jobs and Local Economy

Defined metrics are used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each portfolio under different market scenarios. There are natural trade-offs among these objectives; for example, the portfolio with the lowest expected costs may not be the most stable (lowest band of risks), have the most carbon reductions, or provide the needed flexibility to adapt to changing conditions. The objective of the IRP is to find the right balance of these metrics across a wide variety of future conditions to ensure that the ultimate choice of a portfolio performs well, regardless of the circumstances.

A further description of each metric is provided below.

2.2.1 Rate/Cost Metric

2.2.1.1 Lowest Reasonable Customer Cost

The metric typically used for this objective is Net Present Value of Vectren's Revenue Requirements (NPVRR). The NPVRR is a measure of all costs (for each asset, the cost of generation – capital, O&M, fuel, and any ancillary costs, including transmission, plus the cost of power and capacity purchases etc.) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment. In this way, very different portfolios can be compared on a common metric or value over a long time frame.

2.2.2 Risk Metrics

2.2.2.1 Standard Deviation and the 95th Percentile of Revenue Requirements

In the risk analysis, an assessment of hundreds of scenarios of future market and regulatory conditions were performed on each portfolio. The NPVRR was calculated for each scenario (iteration) and then a frequency distribution of these NPVRRs was calculated. A "standard deviation" is a measure of the variability of the portfolio outcomes. By definition, by taking the mean or average value of the 200 iterations, and then adding and subtracting the value of one standard deviation to the mean value, one captures about 67% of the total observations. Adding or subtracting two standard deviations around the mean captures about 95% of the outcomes. The 95th percentile NPVRR typically represents a plausible worst case outcome of the distribution. Portfolios that have a great deal of uncertainty will have high costs in the worst case outcome. To minimize risk, one would select the portfolio with the lowest measure of dispersion or the lowest standard deviation around the mean value.

2.2.2.2 Market Risk – Reliance on Purchases from the Market

Dispatch modeling informs us of how often units in a given portfolio generate electricity to serve the needs of customers. The balance not met by Vectren's owned generation is supplied by the market. If Vectren relies too much on the market, it subjects Vectren's customers to market price volatility that Vectren would not experience using its own generation assets. Hence, Vectren can measure the percentage reliance on the market as one measure of risk of the portfolio.

2.2.2.3 Capacity Volume Risk

In the base or reference case, the model ensures that adequate capacity purchases are made to meet UCAP reserve margin requirements. When 200 iterations of the model are run, there are high load scenarios where additional capacity purchases may be required to continue to meet the target UCAP requirements. For each portfolio, Vectren calculated on average (across the 200 iterations) how many additional capacity purchases might be required. Since the capacity market is typically more volatile than the energy market, the cost associated with these purchases could be significant.

2.2.3 Environment Improvements Metric

2.2.3.1 Carbon Footprint Reductions from 2012 Levels

Each portfolio was designed to meet existing environmental regulations for carbon dioxide. Some portfolios exceeded the compliance requirements. For example, the Stakeholder Portfolio was designed to achieve a lower carbon footprint than is likely to be required. Vectren tracks the carbon footprint and other emission measures as a measure of environmental compliance and stewardship.

2.2.3.2 SO_2 and NOx Footprint Reductions from 2012-2015 Baseline

Vectren also tracks the sulfur dioxide emission reductions and the nitrous oxide reductions (both regulated by the EPA) over time, which are measured from an average of the 2012-2015 baseline period.

2.2.4 Balance and Flexibility/Diversity Metrics

2.2.4.1 Concentration on One Technology and Number of Technologies Deployed

Vectren must be in a position to be able to quickly adapt to changing market and regulatory conditions. If Vectren relies heavily on the economic performance of any one technology, such as natural gas or coal, higher than anticipated fuel costs for one technology could expose customers to higher prices than a more balanced portfolio. A measure of protection is to have a diverse portfolio that deploys multiple technologies in the resource mix. This approach forms natural hedges in case any single technology becomes obsolete through technological change.

2.2.4.2 Number of Distinct 24/7 Baseload Units

Customers are better off if Vectren has multiple 24/7 baseload facilities to protect against supply disruptions that could impact an individual site, including transmission failures, outages, or other disruptions.

2.2.4.3 Remote Stations

Portfolios that have stations far removed from its load centers are more subject to transmission congestion, transmission failures, or price spikes than local generation.

2.2.4.4 Net Sales

Higher net sale reflects a generation “cushion” created with generation that is available to serve new customers or enable plant retirement. This cushion enables Vectren to satisfy new or growing expected load without exposing customers to wholesale energy market volatilities. In the case of plant retirement, having this cushion allows Vectren to select the optimal time to retire a resource without risking excessive exposure to wholesale energy market volatility.

In addition, duct firing provides economic peaking capacity. Building in duct firing capability during the initial construction of a combined cycle gas fire plant provides

savings and reduces future down time compared to adding the capability later. This consideration also justifies adding capacity in advance of expected need.

2.2.5 Cost-Risk Tradeoff

This trade-off combines two often competing objectives (expected costs and standard deviation) to find the portfolios that meet both objectives. The expected costs are derived using the NPVRR method, while the standard deviation risk is a measure of how much volatility is included in the price movements.

2.2.6 Local Economic Impact

Vectren also considered the impact of portfolios on regional jobs and tax base. Professors from the University of Evansville conducted this economic impact analysis, assessing the impact of coal-fired unit closures and constructing/operating replacement generation within the Vectren service territory.

2.3 DEFINE BASE CASE AND BOUNDARY SCENARIOS

2.3.1 Base Case

The base case scenario represents the most likely future conditions. Vectren surveyed and incorporated a wide array of third-party sources to develop its base case assumptions, several of which reflect a current consensus view of key drivers in power and fuel markets. Base case assumptions include forecasts of the following key drivers:

- Vectren and MISO energy and demand (load)
- Henry Hub and delivered natural gas prices
- Illinois Basin minemouth and delivered coal prices
- National carbon (CO_2) prices
- Capital costs and associated cost curves for various supply side (generation) and demand side resource options
- On- and off-peak power prices

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron, a leading forecasting consultant in the U.S. The forecast is based on historical residential, commercial, and industrial usage and drivers such as appliance saturation and efficiency projections, electric price, long-term weather trends, customer-owned generation, and several demographic and economic factors. More information can be found in Section 4, CUSTOMER ENERGY NEEDS.

For natural gas, coal, and carbon, Vectren used a "consensus" base case view of expected prices by averaging forecasts from several sources. This helps to ensure that reliance on one forecast or forecaster does not occur. For natural gas and coal, 2016 spring forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA are averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie are averaged. Note that spring 2016 forecasts were not available from Ventyx or EVA at the time inputs were created.

Burns & McDonnell provided current costs associated with various generation and storage technologies (single cycle gas turbine, combined cycle gas turbine, combined heat and power, solar, wind, and batteries), while projected cost curves were developed by Pace Global.

DSM costs were developed by escalating 2016 costs with the help of Dr. Richard Stevie, Vice President of Forecasting with Integral Analytics. He created two models using EIA data to develop growth rates used to apply to current costs.

On- and off-peak power price forecasts were developed by Pace Global using the base case assumptions described above, together with Pace Global's view of the greater MISO market, in the AURORAxmp power dispatch model. These key drivers constitute the base case assumptions. More information on modeling inputs can be found in Section 6, SCENARIOS: OPTIMIZATION MODEL INPUTS & ASSUMPTIONS.

2.3.2 Alternative Scenarios

It is important to test technologies against a variety of future market conditions, not just a base or reference case. Hence, Vectren, with the support of Pace Global, selected six alternative scenarios to provide boundary conditions for testing the technologies and portfolios that would be subjected to a full risk assessment (with hundreds of scenarios tested later in the process).

Vectren worked with Pace and also received input from Vectren stakeholders to identify future uncertainties. Major uncertainties were grouped into regulatory risk, technology risk, and market risk.

Using the base case as a starting point, a number of boundary scenarios were developed along three primary axes. The first axis is regulatory, with a high regulatory scenario and a low regulatory scenario. The second axis is technological, with only a high technology scenario (technological innovation is assumed to either continue at the present rate or at an accelerated rate, but not at a "low" rate). The third axis is economic, with a low market/economy scenario and a high market/economy scenario. From these three primary axes come five scenarios that provide a wide range of conditions in which to evaluate various portfolio planning strategies. Additionally, Vectren evaluated a large customer load scenario where Vectren assumes a large load addition of 100 MW in 2024; all else is equal to the base case scenario.

In order to maintain a consistent methodology when crafting the five scenarios[14] from the base case scenario, the forecasting period was divided into short-term (2016-2018), medium-term (2019-2025), and long-term (2026-2036) periods. In the short-term, the market drivers (load, gas, coal, carbon, and capital costs) for all five alternative scenarios are expected to remain the same as the base case scenario. In the medium-term, the market drivers for each alternative scenario (1) stay the same as the base

[14] Also included a scenario where Vectren acquires a 100 MW load addition in 2024; all else is equal to the base scenario.

case scenario, (2) move upward to reach one standard deviation above the base case value by the medium-term timeframe midpoint of 2022, or (3) move downward to reach one standard deviation below the base case value, also by 2022. In the long-term, the market drivers for each alternative scenario maintain their position (same as base case scenario or +/- one standard deviation above/below the base case scenario) or move toward an endpoint in 2036 that is in between +/- one standard deviation. In some cases and for some scenarios, these drivers may push past +/- one standard deviation above/below the base case. For example, in the high regulatory scenario, CO_2 prices push upward past one standard deviation above the base case in order to provide a boundary condition in line with the independent Synapse report[15] forecast for CO_2 prices.

The six scenarios were designed to be consistent with the stochastic distributions (200 iterations) developed for the risk analysis, but on a much more limited scale (six scenarios).

Vectren selected the following scenarios to illustrate the range of potential outcomes:

- Base large load addition;
- A high and a low regulatory case;
- A high and a low economic case; and
- A high technology case.

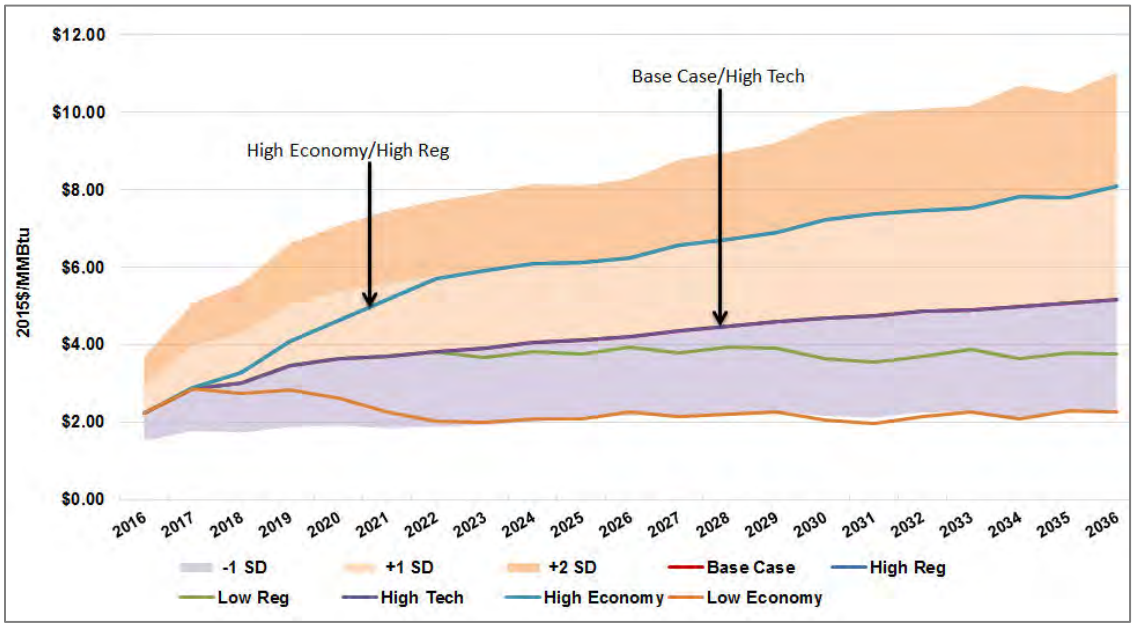
In addition, a consensus between Vectren's staff and its consultants was used to develop directionally whether gas prices, coal prices, load, technology capital costs, retirements and builds, and both carbon emission prices and power prices would move up or down under each of those scenarios. This process was followed more to illustrate what might happen under each of these scenarios in a consistent manner with the risk analysis than to specifically model new regulations or certain technologies.

[15] Synapse Energy Economics, Inc., "Cutting Electric Bills with the Clean Power Plan," March 2016

The six alternate scenarios (described in Section 6 of this document) consist of narrative descriptions of the short-term (2016-2018), medium-term (2019-2025), and long-term (2026-2036) trends in each of the key driver categories described above as well as specific annual or monthly numbers that reflect a shift away from the base case in the medium- to long-term. All scenarios are assumed to mirror the base case in the short-term, though some minor trending apart may begin to occur by 2018. By the middle of the medium-term (2022), each of the drivers will have moved up or down (or stay the same) by one standard deviation relative to the base case, depending on the scenario. By the end of the long-term (2036), each of the drivers will again be one standard deviation above the base case, at the base case, or one standard deviation below the base case.

An illustration of this methodology is given in the graph below for natural gas prices (in constant 2015 dollars). All gas prices begin at $2.23/MMBtu in 2016 and then rise to approximately $2.87/MMBtu in 2017, after which base case gas prices gradually trend upward to $5.13/MMBtu in 2036 while gas prices in the other scenarios either follow the base case or trend higher or lower, depending on the scenario's coordinated input direction. The high technology scenario mirrors that of the base case, while the high economy scenario and high regulatory scenario both move upward to reach +1 standard deviation above the base case in 2022, then remain at +1 standard deviation through the end of the forecast. The low economy scenario sees natural gas prices moving downward to -1 standard deviation below the base case in 2022, and then remains at -1 standard deviation through 2036. Finally, the low regulatory scenario sees natural gas prices trending with the base case through the medium-term, followed by a period of no growth in prices past $4.00/MMBtu.

Figure 2.3 – Natural Gas Price Scenarios, Delivered to Indiana (2015$/MMBtu)



The convention of +/-1 standard deviation is used to maintain a consistent methodology and result when moving key market drivers up or down in each of the scenarios. It should be noted that the historical price distributions differ among the various market drivers and are not necessarily symmetrical (i.e., normally distributed). For example, gas prices are positively skewed because they have no upper boundary and can reach many standard deviations above the historical average, whereas they typically cannot fall below zero (or approximately two standard deviations below the historical average).

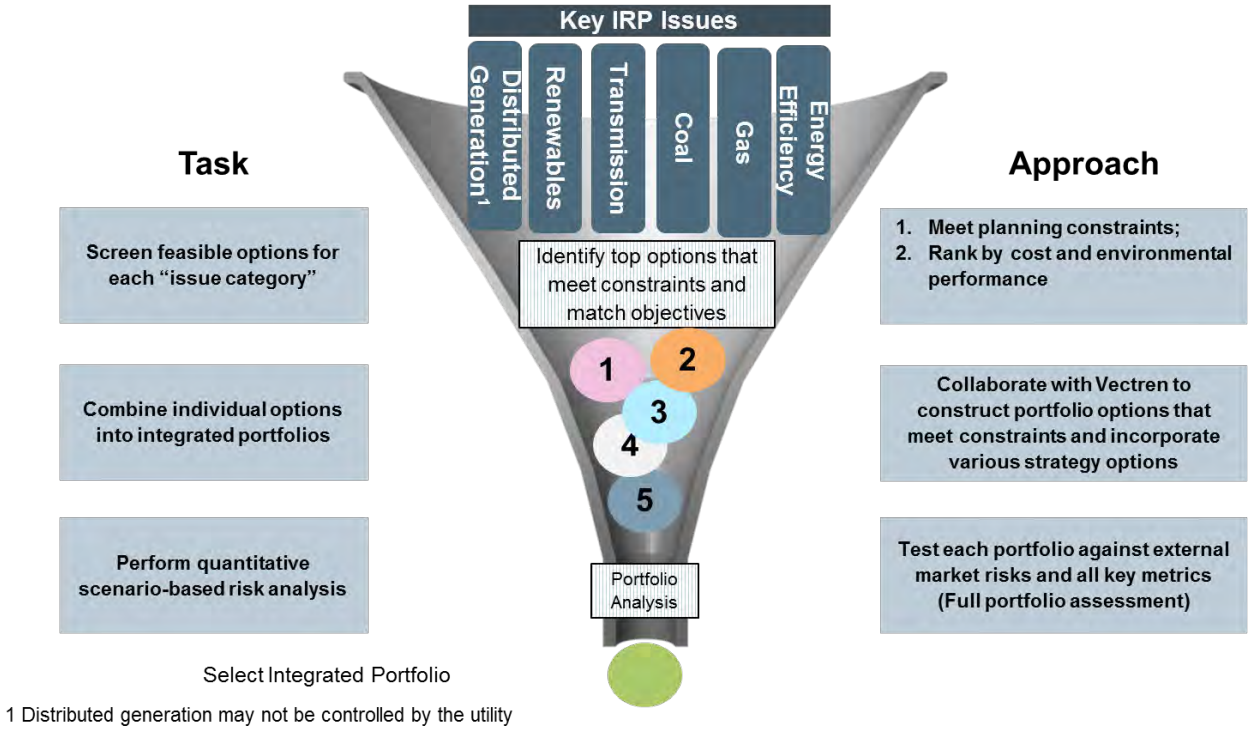
The graphical descriptions of values for each of the key metrics (e.g. load, gas prices, coal prices, technology costs, carbon prices, and power prices) are shown in Section 6.2.2, Coordinated Forecasts for Alternate Scenarios.

2.4 SCREENING ANALYSIS

Burns & McDonnell performed a technology assessment to look at the multitude of different options for power supply (a total of 36 technologies, including renewables, storage, natural gas (including CHP), and coal). To facilitate efficient and timely

modeling, a screening process was developed to filter the technology choices to a smaller data set based on expected operations and levelized cost. The full range of 36 technologies was filtered through this process. The following steps were performed:

Figure 2.4 – Structured Screening Process to Address Issues Efficiently

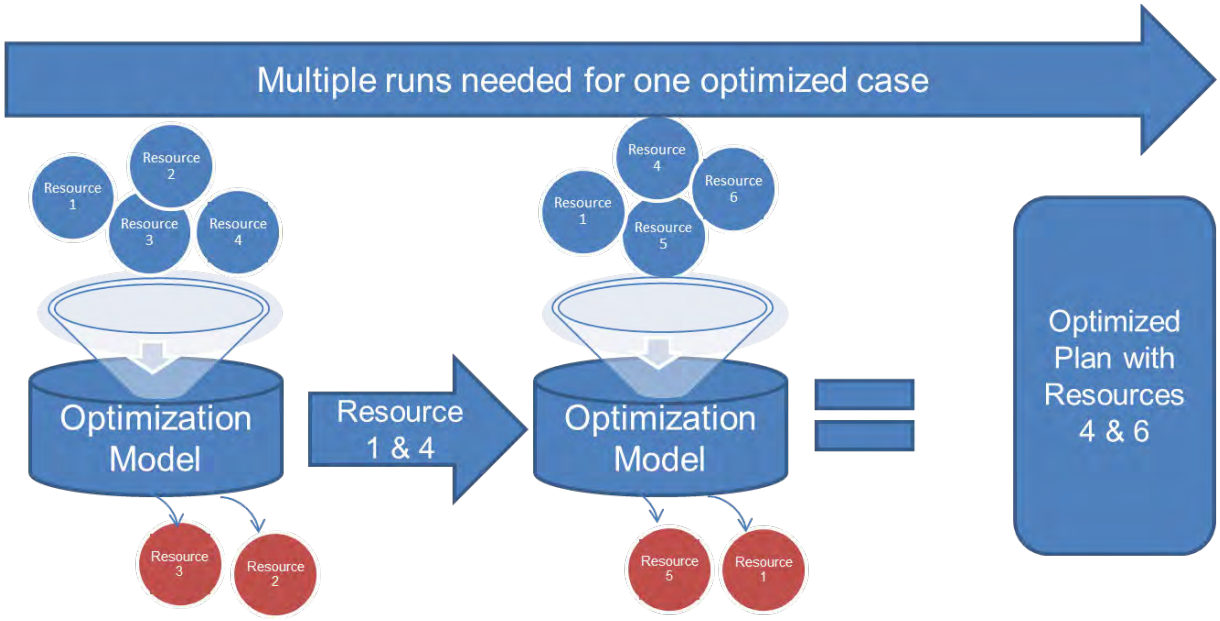


To assess the alternatives on equal footing, Burns & McDonnell performed a busbar, or levelized cost of electricity comparison, for each of the 36 options, focusing on investment costs, operation and maintenance costs, fuel costs, and emissions costs. This screening process allowed for a direct comparison of the anticipated cost of ownership from base load, intermediate, peaking, renewables, and storage alternatives. This step resulted in the elimination of several technologies that performed poorly on a levelized cost basis.

As a next step, the remaining options along with existing facility and demand side alternatives were screened in the Strategist optimization model for the base case and

each of the six scenarios defined in Section 2.3. Due to limitations within the model, not all resource alternatives may be screened in one run. Vectren evaluated more resource alternatives than ever before (coal retirement, existing plant retrofits, multiple blocks of energy efficiency, and demand response, as well as 36 new resource alternatives). In order to accommodate this wide range of options, an iterative process was followed. The model was run with several alternatives. Viable options were kept for the next model run, uneconomic options were screened out, and new options were added in for evaluation. The process was then repeated until all resources were considered and an optimized plan was developed with a small number of resource options for each of the scenarios provided. The illustration below shows the screening process.

Figure 2.5 – Illustrative Example of Strategist Optimization Modeling Process



From this analysis and other objective factors, a list of portfolios was formed in the next stage.

2.5 PORTFOLIO SELECTION

Careful consideration was given to the selection of portfolios in order to address a wide range of objectives, strategies, future market outcomes, and stakeholder concerns; a total of 15 Vectren portfolios were developed for consideration.

First, optimized portfolios were created using Strategist for the base case and each of the six alternate scenarios. The optimized cases produced the least cost portfolio for each of the potential future scenarios, given the modeling inputs. As mentioned above, each scenario represented a possible future state with coordinated inputs for gas, coal, CO_2, market power prices, etc. The intent of this analysis was to produce a wide range of portfolios to test in the risk analysis; however, this modeling produced seven portfolios that looked very similar with a heavy reliance on gas resources and varying levels of energy efficiency. Some included renewables in the late 2020s through the 2030s.

While optimized portfolios are helpful in the analysis process, they may not identify the portfolios that perform well when considering risk and uncertainty. Recognizing this reality and taking stakeholder input into consideration, Vectren worked to develop several diversified portfolios to test in the risk analysis.

During Vectren's public IRP stakeholder meeting on Friday, July 22, 2016, Vectren held a portfolio development workshop to gain input from stakeholders on additional portfolios to be considered within the IRP analysis. The general consensus among the 17 participants was that Vectren should develop a diversified portfolio that moves away from a significant amount of coal by 2025 while renewables and energy efficiency increase. Over the long term, all coal should be retired while renewables and energy efficiency further increase. Vectren used the information gathered from the session to develop two stakeholder portfolios. The first includes some coal, a heavy reliance on renewables and energy efficiency, and some gas in 2024. The second stakeholder

portfolio transitions away from coal altogether by 2024, and replaces it with gas, renewables, and storage.

Finally, Vectren worked to develop several alternate portfolios to test. Portfolios can qualitatively be developed in several ways. One can simply consider various portfolio choices, with trial and error, running them through the optimization tool. Another way is futures based, which is how Vectren's optimized portfolios were developed. Each optimization run resulted in a least cost portfolio for each possible future. A third approach is theme based (all coal, all gas, all renewables, diversified, etc.), which is what Vectren focused on when developing several "diversified portfolios." As a benchmark, Vectren developed the business as usual case (nearly all coal to closely align with Vectren's current portfolio). The optimized base case produced another theme (nearly all gas).

Vectren believes there is value in a balanced portfolio as a way to reduce risk. By having a balanced set of resources available to serve customer load (gas, coal, energy efficiency, wind, solar, etc.), Vectren can reduce the reliance on any one resource type. For example, if gas prices spike or rise more quickly than expected, a portfolio that is nearly all gas has more risk of increasing customer bills. Vectren developed and tested five diversified portfolios with various levels of energy efficiency, demand response, gas, coal, solar, and wind. Below are the 15 portfolios that were tested (Business as Usual, 7 optimized portfolios[16], 2 stakeholder portfolios, and 5 diversified portfolios). More information about these portfolios can be found in Section 7, SCREENING ANALYSIS.

A. Business As Usual (Continue Coal) Portfolio
B. Base Scenario (aka Gas Heavy) Portfolio (Optimized)
C. Base + Large Load Scenario Portfolio (Optimized)
D. High Regulatory Scenario Portfolio (Optimized)

[16] Optimized portfolios were created by Strategist modeling, optimizing on least cost for each scenario (possible future state).

E. Low Regulatory Scenario Portfolio (Optimized)
F. High Economy Scenario Portfolio (Optimized)
G. Low Economy Scenario Portfolio (Optimized)
H. High Technology Scenario Portfolio
I. Stakeholder Portfolio
J. Stakeholder Portfolio (Cease Coal 2024)
K. FBC3, Fired Gas, & Renewables Portfolio
L. FBC3, Fired Gas, Early Solar, & EE Portfolio
M. FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio
N. Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio
O. Gas Portfolio with Renewables Portfolio

2.6 RISK ANALYSIS

The Risk Analysis of each of the portfolios was developed by Pace Global using EPIS' AURORAxmp dispatch model. There were several steps to this process:

- The first step was to develop the input distributions and correlation coefficients for each of the major market and regulatory drivers, including load growth (and shape), gas prices, coal prices, carbon prices, technology capital costs, and power prices. This was done by considering volatility and correlations of each factor in the short term, midterm, and long term.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20 year period. This also formed the basis for the scenario inputs development.
- Portfolios were then run through simulated dispatch for the 200 possible future states using a tool called AURORAxmp. This tool dispatches existing units, builds, and retires units on the basis of least cost optimization for each portfolio combination for each sampled hour over the planning horizon. AURORAxmp will assume that Vectren's portfolio is constant but will allow for economic builds and retirements to occur throughout the region in each scenario based on economic

criteria. Vectren generation, costs, emissions, etc. were tracked for each iteration over time.

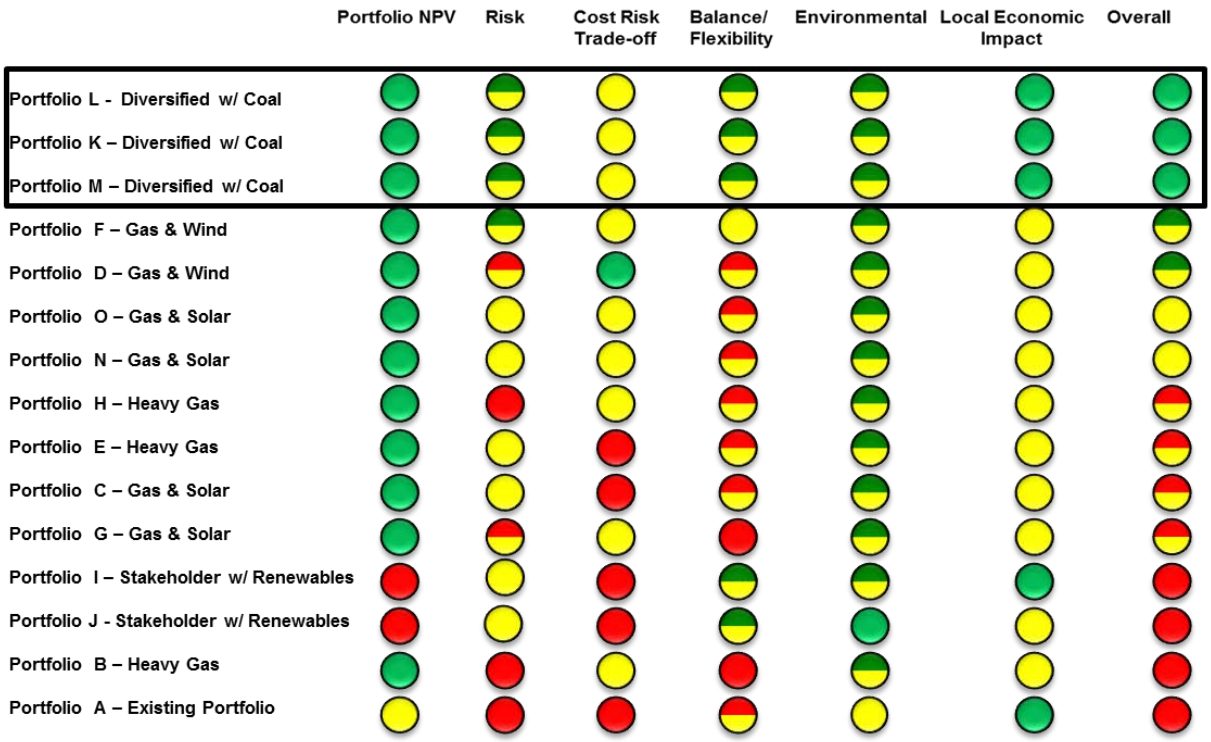
- Next, values for each metric were tracked across all 200 iterations and presented as a distribution with a mean, standard deviation, and other metrics as needed.
- These measures were used as the bases for evaluation in the risk analysis.

More information on the risk analysis can be found in Section 7.2.1, Uncertainty (Risk) Analysis.

2.7 SELECTION OF PREFERRED PORTFOLIO

Selection of the preferred portfolio was based on how well each portfolio met multiple objectives as outlined in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS, under 200 iterations representing different, but cohesive and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives as illustrated below. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations. To help illustrate tradeoffs, Vectren utilized a balanced scorecard, as shown below in Figure 2.6 and further discussed in Section 7.2, EVALUATE PORTFOLIO PERFORMANCE.

Figure 2.6 – Identifying and Evaluating Tradeoffs



SECTION 3
PUBLIC PARTICIPATION PROCESS

3.1 PUBLIC PARTICIPATION PROCESS

Vectren believes in the importance of stakeholder engagement. Vectren's objectives for stakeholder engagement are as follows:

- **Listen**: Understand concerns and objectives
- **Inform**: Increase stakeholder understanding of the Integrated Resource Plan process, key assumptions, and the challenges facing Vectren and the electric utility industry
- **Consider**: Provide a forum for relevant, timely stakeholder feedback at key points in the Integrated Resource Plan process to inform Vectren's decision making

IRP stakeholders include, but are not limited to, Vectren residential, commercial, and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, Vectren shareholders, and elected officials.

The 2016 IRP analysis was heavily influenced by stakeholder input, beginning with input from stakeholders on Vectren's 2014 IRP and ongoing interaction with other energy company stakeholder processes to glean best practices. Additionally, Vectren utilized the IURC director's report to help guide continuous improvement efforts. As a direct result of these engagements, Vectren publically committed to and incorporated several improvement opportunities for the 2016 IRP, listed below:

- Vectren constructed scenarios (possible future states) with coordinated data inputs with a well-reasoned narrative
- Vectren conducted a probabilistic risk analysis to explore the outer bounds of probability
- Future energy company-sponsored energy efficiency was modeled as a resource (not built into the load forecast)
- Vectren evaluated if retirement made sense for any of Vectren's existing coal generating units within the 20-year time frame under each scenario

- Vectren continues to monitor Combined Heat and Power (CHP) developments and included CHP as a resource option
- Vectren considered conversion of coal units to gas
- Renewable options were fully considered in this analysis
- Updated the IRP document format to be more readable

Another commitment that all Indiana investor-owned utilities, including Vectren, made was to help educate stakeholders on the IRP process. As such, Vectren's 2016 engagement with stakeholders began in February by participation in a joint utilities Integrated Resource Plan Stakeholder Education Session. Duke Energy Indiana, Indiana Michigan Power (I&M), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), and Vectren jointly presented an educational session to discuss the foundation of the IRP process. This all-day meeting was hosted on February 3, 2016. Topics covered at the meeting included load forecasting, resource options, scenarios & sensitivities, Regional Transmission Operators (RTO), and resource modeling. Recordings and materials were posted to www.vectren.com/irp as a resource for stakeholders who want to know more about the general process.

Three public stakeholder meetings were held at Vectren headquarters in Evansville, IN. Dates and topics covered are listed below:

- April 7, 2016
    - Vectren IRP Process Overview
    - Discussion of Uncertainties
    - Long-term Energy and Demand Forecast
    - Customer-Owned Distributed Generation
    - 2016 IRP Technology Assessment Generation Resource Alternatives
    - Generation Retrofit Alternatives
    - Energy Efficiency Modeling Discussion
- July 22, 2016

    - Environmental Compliance
    - Base Case/Modeling Inputs
    - Busbar Analysis and Optimization Modeling
    - Scenario Development
    - Stakeholder Input to Portfolio Selection
- November 29, 2016
    - Presentation of the Preferred Portfolio
    - Optimization Modeling Results and Portfolio Development
    - Risk Analysis Results

Additionally, Vectren held a DSM Modeling Information Session on October 14, 2016 with the Vectren DSM Oversight Committee, which includes the Office of Utility Consumer Counselor (OUCC) and Citizens Action Coalition (CAC). Additionally, Indiana Utility Regulatory Commission (IURC) staff attended. Other Vectren stakeholders participated via webinar. The main topics discussed were energy efficiency modeling inputs, including energy efficiency pricing and how energy efficiency was modeled on a consistent and comparable basis with supply side options (power generation options).

Meeting materials, workshop results, and summaries of each meeting can be found on www.vectren.com/irp and also in Technical Appendix Attachment 3.1 Stakeholder Materials.

3.2 STAKEHOLDER INPUT

During the course of the 2016 IRP, stakeholders provided their input in several ways: 1) verbal feedback through question/answer sessions during public stakeholder meetings; 2) through participation in Vectren stakeholder workshops; and 3) via written feedback/requests.

Vectren worked diligently to have an open forum for stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each Vectren

stakeholder meeting was opened by Carl Chapman, Chairman, President, and Chief Executive Officer of Vectren. He and other senior management, Vectren subject matter experts, and expert consultants actively participated in each meeting to help address stakeholder questions/concerns. Additionally, Vectren addressed stakeholder questions outside of public meetings via irp@vectren.com in a timely manner.

During the first stakeholder workshop on April 7, 2016 Vectren held a session to discuss future uncertainties to be considered in scenario development. The following topics were raised by stakeholders:

- Consider additional environmental regulations that have not yet been proposed
- Factor in the Clean Power Plan (CPP) compliance costs
- Consider how electric vehicle technology affects the plan
- Consider distributed generation risk
- Consider diversifying generation
- Consider political/regulatory risk
- Consider additional cogeneration being developed within the Vectren territory

Vectren agrees that these are key uncertainties and included them within scenario development. Please see Section 6.2, DEVELOPMENT OF ALTERNATE SCENARIOS for more information.

During the second public stakeholder meeting on July 22, 2016 Vectren held a workshop to gather input from stakeholders to gain their insight on a preferred resource portfolio. Two stakeholders (Valley Watch and the Sierra Club) made presentations to the audience. Their meeting materials can be found in Technical Appendix Attachment 3.1 Stakeholder Materials. Following these presentations, stakeholders formed several groups and provided feedback on their preferred resource portfolios.

The general consensus among the participants was that Vectren should develop a diversified portfolio that moves away from a significant amount of coal by 2025 while

renewables and energy efficiency increase. Over the long term, all coal should be retired while renewables and energy efficiency further increase. Several stakeholders expressed concern for the local economic impact if all coal were to be retired in the near to midterm.

Information gathered at this session was used to develop two stakeholder portfolios that were fully tested in the risk analysis. One portfolio kept two coal units through 2035, and the other retired all coal by 2035. For a full description of workshop results, please see Technical Appendix Attachment 3.1 Stakeholder Materials. These portfolios are described in Section 7 Developed Portfolios. Additionally, risk analysis results can be found in Section 8.1, SCORECARD COMPARISON.

On October 14, 2016 Vectren held discussions with stakeholders on EE modeling for the IRP. A stakeholder suggested that breaking the link between EE selected in the near term versus long term as costs increase over time may constrain the model as it could result in the model not selecting EE in the short term. Vectren requested feedback/suggestions from stakeholders on how we could model differently (i.e., model in 3 year increments) and no specific feedback was provided at the time.

Based on stakeholder feedback, Vectren performed additional analysis which looked at the competitiveness of EE over a 3-year block from 2018-2020 rather than selecting the block for entire study period. The 3-year timeframe was selected in order to provide insights into cost effectiveness of EE programs through the next DSM and IRP filing. The analysis results showed no blocks of EE in the lowest NPV plan under the base scenario. EE Blocks 1-4 represented a cost increase of 0.07% over a 20-year Strategist NPV, while EE Blocks 1-8 resulted in a cost increase of 0.96%. The results indicated that blocks 1-4 in 2018-2020 are relatively similar cost as a plan without any additional blocks of EE.

On November 2, 2016 Vectren received a position paper from Ms. Jean Webb, a residential Vectren customer. Her positions are included in Technical Appendix Attachment 3.1 Stakeholder Materials. Included in the paper was a suggestion to review Lazard's Unsubsidized Levelized Cost of Energy Analysis Version 9.0. In Ms. Webb's paper she mentioned that "Lazard's reported that universal solar ranged from $43 to $70 per MWh, whereas Vectren's levelized numbers were from $190 to $210 per MWh."

Vectren has carefully considered many different technologies to potentially supply customer power, including renewable energy from solar power and would suggest that the numbers Ms. Webb references do not fully capture the cost and potential energy output reflective of a solar project located in southwestern Indiana. The $43 to $70 per MWh levelized cost of solar referenced from the Lazard study – per the footnote included within the paper – "Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors". Further, the costs presented by Lazard do not include site-specific and owner-specific conditions such as land, permitting, legal fees, and transmission/distribution interconnection. These costs cannot be ignored when considering a solar project compared to other alternatives.

Vectren reviewed and illustrated the impact of different assumptions to the levelized cost of solar at its last public stakeholder meeting (held on November 29, 2016), noting that capacity factor and total cost to build are two of the more impactful assumptions. Vectren believes the costs assumed for a solar project used within this IRP are reasonable.

In the final Vectren IRP Stakeholder meeting held on November 29, 2016 a stakeholder asked if health care costs were included in the local economic impact analysis. They were not included within the economic impact analysis. Vectren worked with the University of Evansville to understand the economic impact to the local community

should Vectren coal plants shut down. The software that they utilized does not include a mechanism for calculating health impacts. However, health impacts are considered within known and expected EPA regulations, which were factored into the IRP analysis.

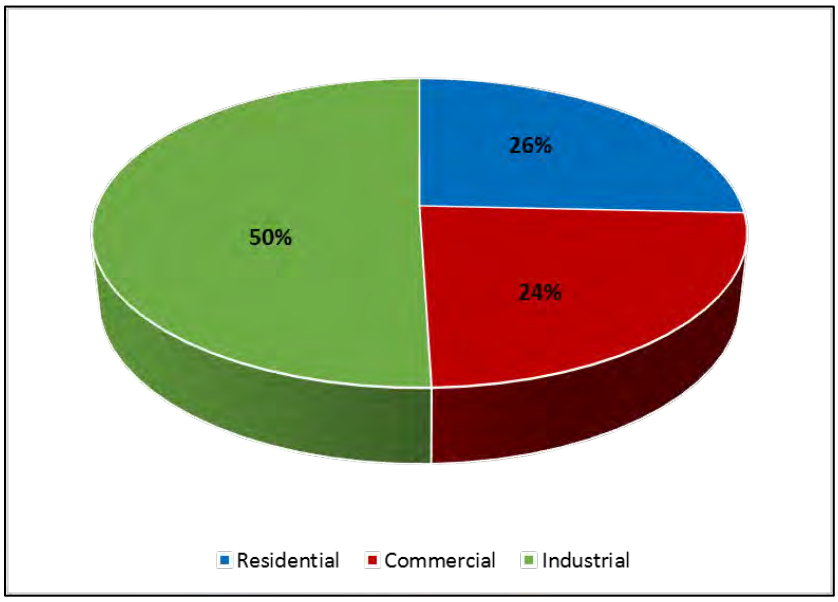
According to EPA, the Clean Air Act (CAA) was designed by Congress to protect public health and welfare from different types of air pollution. The CAA requires EPA to establish national ambient air quality standards for criteria pollutants based upon levels deemed necessary to protect public health, and in the case of "primary" standards, levels deemed necessary to not only protect public health in general but also the health of sensitive populations such as asthmatics, children and the elderly. In addition there are specific provisions to address hazardous or toxic air pollutants that pose health risks which are technology based. Congress requires EPA to issue "maximum achievable control technology (MACT) emission standards which are reviewed every 8 years. As part of the review, EPA is required to give consideration to whether more stringent, risk-based standards are required to protect public health with an ample margin of safety. Since EPA clean air standards, both national ambient air quality standards and public health-based risk standards for hazardous air pollutants already take public health into account, there is no basis for trying to further account for health impacts from the preferred portfolio.

SECTION 4
CUSTOMER ENERGY NEEDS

4.1 CUSTOMER TYPES

Vectren serves approximately 144,000 electric customers in Southwest Indiana. The service area includes a large industrial base with industrial customers accounting for approximately 50% of sales in 2015. The residential class accounted for 26% of sales and the commercial class 24% of sales. Total system 2015 energy requirements (including losses) were 5,737 GWh with system peak (hour of maximum demand) reaching 1,089 MW. 2015 hourly system load data can be found in Technical Appendix 4.2 2015 Vectren Hourly System Load Data. The weather-normalized peak estimate for 2015 was 1,035 MW. Figure 4.1 shows 2015 class-level sales distribution.

Figure 4.1 – 2015 Vectren Sales Breakdown



4.2 FORECAST DRIVERS AND DATA SOURCES

The main drivers of the energy and demand forecast include the following: historical energy and demand data, economic and demographic information, weather data, equipment efficiencies, and equipment market share data.

Itron used over ten years of historical energy and demand data within the sales and demand forecasts. This data is maintained by Vectren in an internal database and was provided to Itron. Energy data is aggregated by rate class for the purposes of forecasting. There are two major rate classes for residential customers: the standard residential rate and the transitional electric heating rate. Information for these rates is combined for the purposes of forecasting residential average use per customer. Similarly, small commercial (general service) rates are combined to produce the commercial forecast and large customer rates are combined to produce the industrial forecast. The demand forecast utilizes total system demand.

Economics and demographics are drivers of electricity consumption. Historically, there has been a positive relationship between economic performance and electricity consumption. As the economy improves, electricity consumption goes up and vice versa. Economic and demographic information was provided by Moody's Economy.com, which contains both historical results and projected data throughout the IRP forecast period. Examples of economic variables used include, but are not limited to, population, income, output, and employment.

Weather is also a driver of electric consumption. Vectren's peak demand is typically in summer when temperatures are hottest. Air conditioning drives summer usage. Normal weather data is obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. Vectren utilizes data over a 30-year period for the sales forecast and a 10-year period for the demand forecast in order to capture recent weather activity.

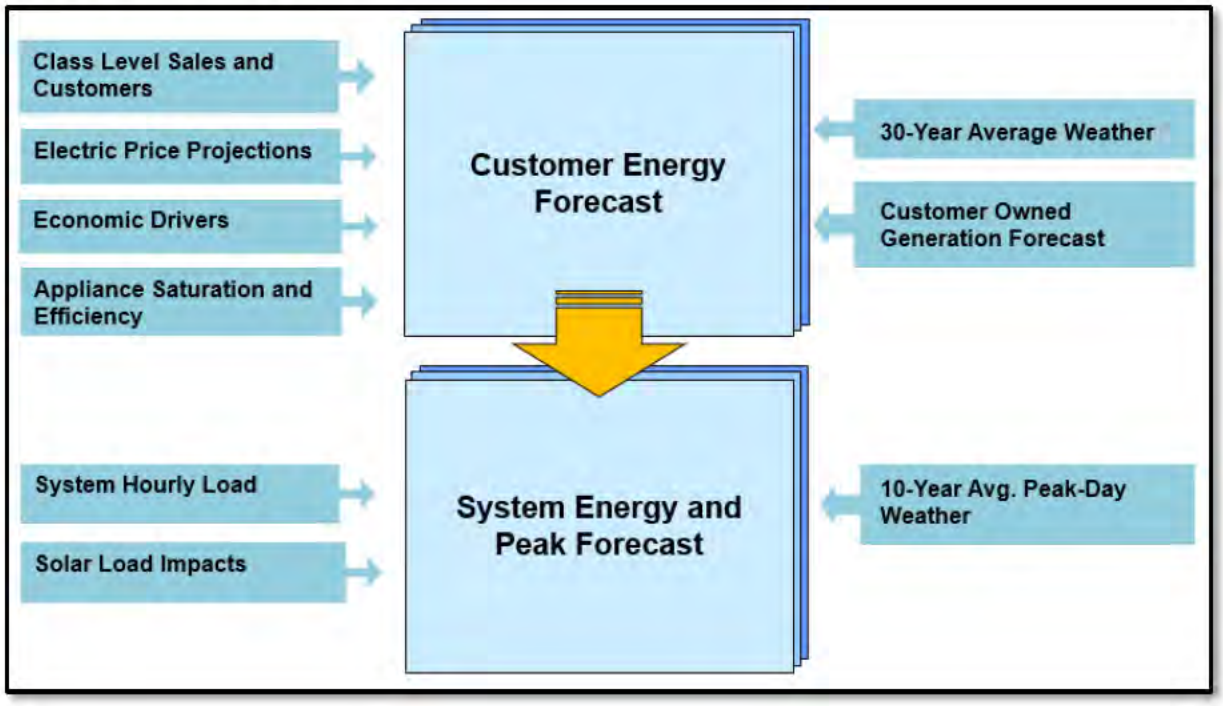
Itron, Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following: electric furnaces, heat pumps, geothermal, central air conditioning, room air

conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data has been adjusted to Vectren's service territory based on the latest appliance saturation survey data.

4.3 MODEL FRAMEWORK

The long-term energy and demand forecast was developed from the customer class total and end-use sales forecast. Customer class (residential, commercial, industrial, and street lighting) sales forecasts were based on monthly sales forecast models that related customer usage to weather conditions, economic activity, price, and end-use ownership and efficiency trends. The relationship was estimated using linear regression models. Energy requirements were then derived by adjusting the sales forecast upwards for line losses. Peak demand was forecasted through a monthly peak-demand linear regression model that related peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling, and other use) derived from the class sales forecasts. Figure 4.2 shows the general framework and model inputs.

Figure 4.2 – Class Build-up Model



In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance ownership trends, end-use efficiency changes, increasing housing square footage, and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. This type of model is known as a Statistically Adjusted End-Use (SAE) model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. Both residential and commercial sales were forecast using SAE models. Industrial sales were forecast using a generalized econometric model that related industrial sales to seasonal patterns and industrial economic activity. Street light sales were forecast using a simple seasonal trend model. The demand model is an SAE peak model.

4.4 CUSTOMER OWNED DISTRIBUTED GENERATION

Distributed generation (DG) is an electrical source interconnected to Vectren's transmission or distribution system at the customer's site. The power capacity is typically small when compared to the energy companies' centralized power plants. DG systems allow customers to produce some or all of the electricity they need. By generating a portion or all of the electricity a customer uses, the customer can effectively reduce their electric load. With respect to Vectren's electric service territory, DG will likely take these forms:

Small – 10 kW and under – roof-top photovoltaic (PV) systems, small wind turbine, etc. interconnected at distribution secondary voltage (120/240 V, etc.)

Medium – 10 kW to 10 MW – large scale PV systems, wind turbine(s), micro-turbine(s), etc. interconnected at distribution primary voltage (4 kV or 12 kV)

Large – 10 MW and over – heat recovery steam generator, combustion turbine, etc. interconnected at transmission voltage (69 kV and over)

Most renewable DG systems only produce power when their energy source, such as wind or sunlight, is available. Due to the intermittency of the power supply from DG systems, there will be times when the customer needs to receive electricity from Vectren. Conversely, when a DG system produces more power than the customer's load, excess power can be sent back to Vectren's electric system through a program called net metering. The customer is charged the retail rate for the net power that they consume.

It should be noted that Vectren's forecast of customer owned solar generation is a market based forecast; Vectren did not limit the forecast to 1% of Vectren's installed capacity, consistent with current regulations.

4.4.1 Current DG

As of December 2015, Vectren had approximately 130 residential solar customers and 15 commercial solar customers, with an approximate installed capacity of 1.2 MW. Based on recent solar installation data, the residential average size is 7.8 KW, while the commercial average system size is 16.9 KW. Vectren has incorporated a forecast of customer owned photovoltaic systems into the sales and demand forecast.

Vectren is aware of one large CHP system that is currently being installed within the Vectren service area. A CHP system is projected to be online in 2017. Vectren monitors Combined Heat and Power (CHP) developments in its service area and adjusts the load forecast for any known, future customer owned CHP installations.

4.4.2 Solar DG Forecast

The primary factor driving system adoption is customer economics. Based on analysis of state-level system adoption, Itron has found a strong correlation between customer adoption and simple payback. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. On an aggregate basis, simple payback also works well to explain leased system adoption; return on investment drives the leasing company's decision to offer leasing programs.

Solar investment payback is calculated as a function of system costs, federal and state tax credits and incentive payments, retail electric rates, and treatment of excess generation (solar generation returned to the grid); for this forecast, Vectren assumed excess generation is credited to the customer at retail energy rates.

Itron developed a solar adoption model that predicts residential solar saturation by relating historical residential solar saturation to simple payback period. The results of this model were then multiplied by the residential customer forecast to determine the number of residential systems expected to be installed. The installed solar capacity

forecast is the product of the solar customer forecast and average system size (measured in kW).

In the commercial sector there have been too few adoptions to estimate a reasonable model; low commercial system adoption is found across the country. Itron believes limited commercial adoption reflects higher investment hurdle rates, building ownership issues (i.e., the person that owns the building often does not pay the electric bill), and physical constraints as to placement of the system. For this forecast, Itron assumed that there would continue to be some commercial rooftop adoption by allowing commercial adoption to increase over time based on the current relationship between commercial and residential adoptions rates.

As of December 2015, the saturation of residential solar customers was about 0.1% of customers. This is expected to be 4.1% (approximately 5,300) by 2036. Commercial saturation is expected to grow to 2.8% over the same time frame.

By 2036, it is expected that over 50 MW of installed customer owned solar capacity will be in place, generating over 67,000 MWhs of energy. The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. For example, system peak is generally around 4:00 pm, while maximum solar output is at noon. Even though solar capacity reaches over 50 MW by 2036, solar load reduces Vectren's system peak demand by only 16 MW. The table below shows the forecast of customer owned solar generation, which has been netted out of Vectren's sales and demand forecast.

Figure 4.3 – Solar Capacity and Generation

Year	Total Generation MWh	Installed Capacity MW	Demand Impact MW
2016	3,143	2.6	0.8
2017	8,341	6.9	2.2
2018	16,603	13.6	4.3
2019	23,681	18.3	5.8
2020	35,097	27.9	8.9
2021	44,497	34.5	11.0
2022	47,641	36.0	11.4
2023	49,054	37.0	11.8
2024	50,574	38.1	12.1
2025	51,874	39.2	12.5
2026	53,297	40.2	12.8
2027	54,712	41.3	13.1
2028	56,253	42.4	13.5
2029	57,532	43.4	13.8
2030	58,974	44.5	14.2
2031	60,390	45.6	14.5
2032	61,933	46.6	14.8
2033	63,216	47.7	15.2
2034	64,726	48.8	15.5
2035	66,223	50.0	15.9
2036	67,856	51.1	16.2
CAGR 2017-2036	11.7%	11.1%	11.1%

4.4.3 Potential Effects on Generation, Transmission, and Distribution

Net metering customers currently offset a small amount of load on each respective distribution circuit, which has not caused significant operational issues for Vectren. At higher levels of DG penetration, Vectren would encounter more operational issues and would need to allocate more resources to mitigate these issues. Some examples of potential issues would include:

- **High voltage mitigation** – With a high penetration of DG, distribution feeder voltage profiles could become unacceptably high when light loading periods coincide with high DG output. A mitigation strategy would need to be developed to control voltage at acceptable levels.

- **Protection system modifications** – Traditionally, electric distribution feeders have been designed as unidirectional from the energy company to the customer. Voltage regulation and feeder protection strategies are designed based on this premise. With high DG penetration under light load with high DG output, power flow could reverse from the customer to the energy company. A mitigation strategy would need to be implemented to correct for the change in the system's operating characteristics.
- **Power quality and harmonics mitigation** – Power quality issues are one of the major impacts of high photovoltaics penetration levels on distribution networks. Power inverters used to interface PV arrays to power grids increase the total harmonic distortion of both voltage and current, which can introduce heating issues in equipment like transformers, conductors, motors, etc. A mitigation strategy would need to be implemented to correct for the change in the system's operating characteristics.
- **Short term load forecast uncertainty** – At higher levels of DG penetration, load forecasting becomes more difficult. DG resources work to offset the customer's load, but their output can be variable depending upon weather conditions. Load forecasting techniques would need to be more granular and would need to incorporate provisions for DG response to short-term weather conditions.
- **Capacitor banks on the distribution feeders** – Capacitor banks are used to improve power factor and also raise voltages along the lines. These are strategically placed based on load/distance from the normal source (substation). Once additional sources (DG) are added to the circuits, the capacitor banks may no longer be in the optimal location for power factor correction or voltage changes. This could negatively impact the power factor and voltage level of the circuit, if a circuit has a high enough DG concentration.

Vectren's electric rates are designed to recover the fixed costs of providing service (transmission, distribution, metering, etc.) via energy and (for large customers) demand charges, along with an associated fixed monthly customer facilities charge. The fixed

monthly charge does not reflect the full amount of fixed costs that Vectren incurs to provide retail electric service. DG customers (who generate a portion of their own electricity but still rely on the electric grid) avoid paying the fixed costs of the grid that are included in the energy charge, which leads to Vectren's under recovery of the cost of providing service. Over time, as base rates are updated periodically, these costs shift to non-net metering customers, resulting in a subsidy being paid to net metering customers.

4.5 BASE ENERGY AND DEMAND FORECAST

For the IRP filing, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is now considered a supply option and not a reduction to demand. Excluding DSM, total energy requirements and peak demand (after 2017) are expected to average 0.5% annual growth over the next 20 years. The table below shows Vectren's energy and demand forecast; the forecast includes the impact of customer owned distributed generation and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on Vectren long-term energy and demand forecasts, including load shapes, see Technical Appendix Attachment 4.1 2016 Vectren Long-Term Electric Energy and Demand Forecast Report.

Figure 4.4 – Energy and Demand Forecast[17]

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2016	5,913,198		1,164		896	
2017	5,309,089	-10.2%	1,094	-6.0%	825	-7.9%
2018	5,368,438	1.1%	1,104	0.9%	836	1.2%
2019	5,397,983	0.6%	1,109	0.5%	841	0.6%
2020	5,449,432	1.0%	1,117	0.7%	851	1.2%
2021	5,451,608	0.0%	1,118	0.0%	852	0.1%
2022	5,472,381	0.4%	1,122	0.4%	855	0.4%
2023	5,497,316	0.5%	1,126	0.4%	858	0.4%
2024	5,529,346	0.6%	1,132	0.5%	863	0.6%
2025	5,549,264	0.4%	1,136	0.4%	866	0.3%
2026	5,573,239	0.4%	1,141	0.4%	869	0.4%
2027	5,600,616	0.5%	1,147	0.5%	873	0.5%
2028	5,637,119	0.7%	1,154	0.6%	878	0.6%
2029	5,662,724	0.5%	1,159	0.5%	882	0.4%
2030	5,687,266	0.4%	1,165	0.5%	885	0.4%
2031	5,711,753	0.4%	1,170	0.5%	888	0.4%
2032	5,744,206	0.6%	1,177	0.6%	893	0.5%
2033	5,766,607	0.4%	1,183	0.4%	896	0.3%
2034	5,796,861	0.5%	1,189	0.5%	900	0.5%
2035	5,814,295	0.3%	1,193	0.3%	902	0.2%
2036	5,837,850	0.4%	1,198	0.4%	905	0.4%
CAGR 2017-2036		0.5%		0.5%		0.5%

4.6 DISCUSSION OF BASE LOAD, INTERMEDIATE LOAD, AND PEAK LOAD

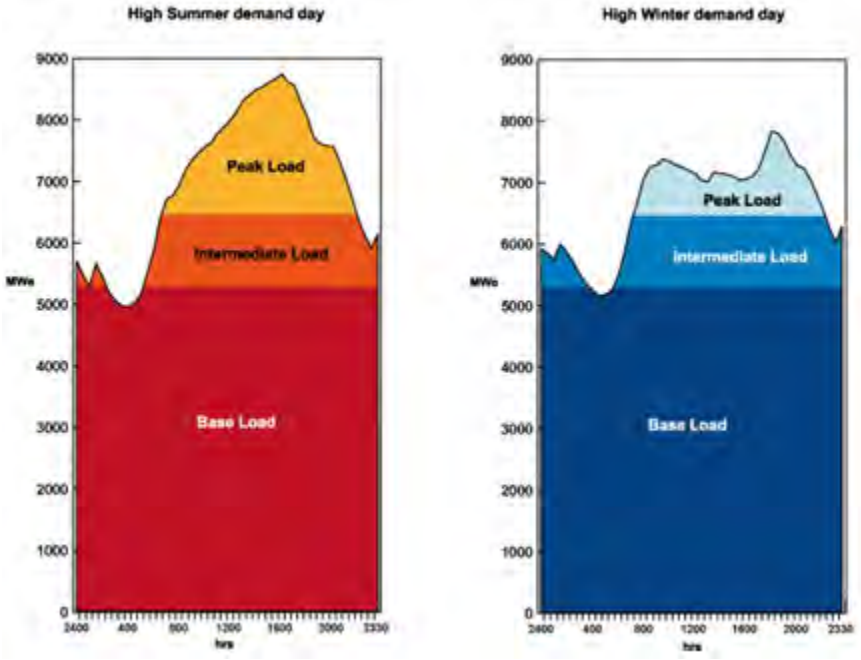
There are three levels of electric load: base load, intermediate load, and peak load. Each level is served by different resource types. Base load is the minimum level of demand on an electrical supply system over 24 hours. Base load is primarily served by power plants which can generate consistent and dependable power. Intermediate load is a medium level of demand. Plants can operate between extremes and generally have output increased in the morning and decreased in the evening. Peak load is the

[17] 2016 2016 IRP sales and demand forecast provided to MISO differed slightly in order to match MISO's requirements which necessitated the following two adjustments : 1) incorporated the preferred level of DSM, and 2) adjustment made on the supply and demand side to account for expected customer co-generation unit in 2017.

highest level of demand within a 24-hour period. The annual peak hour is typically between June and September, when weather is hottest. For modeling purposes, Vectren uses August as the peak month. Typically, peak demand is served by units that can be switched on quickly when additional power is needed.

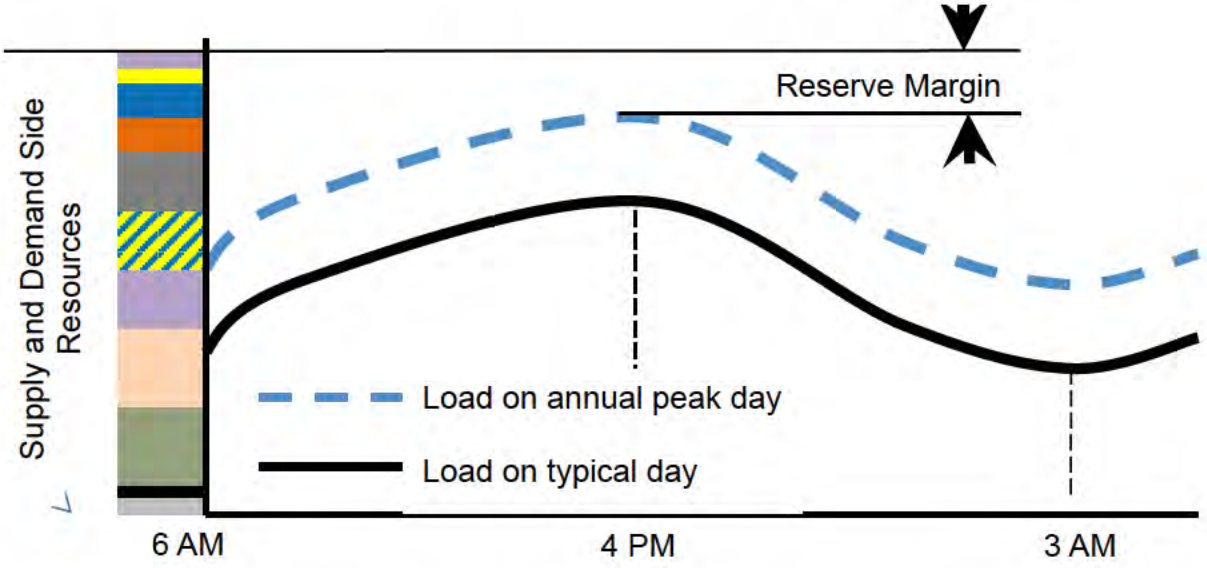
The graphic below shows an illustrative example of summer and winter peak load.

Figure 4.5 – Typical Load Curve Illustrations (Summer and Winter)



Energy companies must have enough resources (supply side generation or demand side energy efficiency & demand response) to meet the annual peak load, plus a reserve margin for reliability purposes, which is required by Vectren's regional transmission operator. The illustration below shows the load on a typical day and load on the peak day with the reserve margin requirement.

Figure 4.6 – Illustration of Load Curve and Planning Reserve Margin



4.7 PLANNING RESERVE MARGIN DISCUSSION

The planning reserve margin requirement is set by MISO (Midcontinent Independent System Operator), which is Vectren's Regional Transmission Operator (RTO).

4.7.1 MISO

MISO, headquartered in Carmel, Indiana, with additional offices in Little Rock, Arkansas, Metairie, Louisiana, and Eagan, Minnesota, was approved as the nation's first Regional Transmission Organization in 2001. Today, MISO manages one of the world's largest energy and operating reserves markets; the market power capacity was 175,600 MW as of June 1, 2016. This market operates in 15 states and 1 Canadian province.

MISO administers its Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). As a vertically integrated energy company with the responsibility and obligation for serving load within the MISO footprint, Vectren has integrated many functions with the operating procedures of MISO. This integration involves the coordinated operation of its transmission system and generating units, and

the functions range from owning and operating generation and transmission to complying with certain reliability standards. These standards include the planning and operation of resources to meet future load needs that are set by the North American Electric Reliability Corporation (NERC) and the regional reliability entity Reliability First Corporation, both of which are overseen by the Federal Energy Regulatory Commission (FERC).

With a native peak load of about 1,160 MW, Vectren is less than 1% of the MISO market footprint and is 1 of 36 local balancing authorities. In addition, the Vectren transmission system supports multiple municipalities. The total control area or Local Balancing Area (LBA) is approximately 1,300 MW.

4.7.2 MISO Planning Reserve Margin Requirement (PRMR)

MISO helps to ensure Resource Adequacy by establishing the Planning Reserve Margin (PRM) with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The PRM is a measure of available capacity over and above the capacity needed to meet normal peak demand levels. Reserve margin and reserve capacity are synonymous. For a producer of energy, it refers to the ability of a producer to generate more energy than the system normally requires. Regulatory bodies usually require producers to maintain a constant reserve margin of 10-20% of normal capacity as insurance against breakdowns in part of the system or sudden increases in energy demand. PRMs are needed to cover: planned maintenance, unplanned or forced outages of generating equipment, de-ratings in the capability of generation resources and demand response resources, system effects due to reasonably anticipated variations in weather, and variations in customer demands or forecast demand uncertainty.

4.7.2.1 Mechanics of the PRMR

The PRM calculation is driven by the following: external non-firm support, load forecast uncertainty, load, and generation. External non-firm support refers to the diversity of

load between MISO and neighboring systems outside of MISO that allow for limited support and transfer of capacity. An example would be generators in PJM providing capacity to MISO load. Load forecast uncertainty exists due to the variability of economics and weather that impact the demand for energy and increases the uncertainty of forecasts. A robust economy with extreme weather patterns typically leads to higher energy demand. Conversely, a depressed economy with moderate weather tends to lead to reductions in energy demand. Additionally, the ability, or lack there-of, to predict weather and the economy and whether load growth will be positive or negative greatly impacts the amount of reserves needed to reliably meet load needs. The greater the Load Forecast Uncertainty, the greater the PRMR. Finally, generation as it is modeled in terms of capacity and firm imports, impacts the PRM calculation based on the size and outage rate of the generators. A year in which there are a large number of generator outages with long durations will increase the PRM. The chart below is intended to show the impact on the PRMR due to increases in the individual driver (external non-firm support, load forecast uncertainty, load, and generation).

Figure 4.7 – Planning Reserve Margin Drivers

	External Non-Firm Support	Load Forecast Uncertainty	Load (Forecast Demand)	Generation (Size and Outages)
Increase in the Driver	⬆	⬆	⬆	⬆
Impact on the PRM%	⬇	⬆	⬇	⬆

MISO coordinates with stakeholders to determine the appropriate PRM for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO Coincident Peak Demand for that planning year. The probabilistic analysis uses a Loss of Load Expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for

the next planning year is one day in 10 years, or 0.1 days per year. The minimum amount of capacity above Coincident Peak Demand in the MISO Region required to meet the reliability criteria is used to establish the PRM. The PRM is represented as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO Region.

The LOLE study sets the Local Reliability Requirement (LRR) for the planning year for each of MISO's zones. MISO's Zone 6[18] in planning year 2016-2017 is required to have a UCAP PRM of 7.6%. This number changes each year based on changes in the factors listed above. Given that the PRM changes from year to year, it is good to have some resources available above the PRM. The full MISO report can be found in Technical Appendix Attachment 4.3 MISO LOLE Study Report.

Since 2013, MISO's Reserve Margin has declined. As MISO starts to operate at or near the Planning Reserve Margin Requirement, it is likely that MISO will begin calling Emergency Operating Procedures more often than in the past to access emergency-only resources, such as Load Modifying Resources (LMR) and Behind the Meter Generation (BTMG). Emergency Operating Procedures (EOPs) guide system operator actions when an event occurs on the electric system that has the potential to, or actually does, negatively impact system reliability.

[18] MISO Zone 6 covers much of Indiana and a small portion of Kentucky.

SECTION 5
RESOURCE OPTIONS

5.1 CURRENT MIX

Generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. Units that cost less to run are dispatched before units that cost more. Vectren's larger coal units tend to be base load units. Intermediate units may cycle on and off frequently and may sit idle seasonally. Vectren's smallest coal unit sees this type of service. Peaking units have the most expensive energy costs per kWh and are only started when energy demand exceeds 24/7 baseload capacity. Currently, Vectren's gas turbines are dispatched during these peak periods to assure reliability. These peaking units may only run for a few hours and remain idle for long periods of time until called on.

Vectren's current generation mix consists of approximately 1,360 megawatts (MW) of installed capacity. This capacity consists of approximately 1,000 MW of coal fired generation, 245 MW of gas fired generation, 3 MW of landfill gas generation, purchase power agreements (PPA's) totaling 80 MW from wind, and a 1.5% ownership share of Ohio Valley Electric Corporation (OVEC) which equates to 32 MW.

The table below references both installed capacity (ICAP) and unforced capacity (UCAP). Installed capacity is also referred to as nameplate capacity. This is the maximum output that can be expected from a resource. Unforced capacity is the amount of capacity that can be relied upon to meet peak load. MISO uses UCAP for planning purposes. The UCAP accreditation recognizes that all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year reliability history and a weather normalized capability verification to determine the UCAP accreditation of each unit. Vectren used the MISO 2016-2017

UCAP accreditation values along with the MISO UCAP planning reserve margin requirements (7.6% PRM) in the current IRP.

Figure 5.1 – Vectren Generating Units

Unit	Installed Capacity ICAP (MW)	Unforced Capacity UCAP (MW)	Primary Fuel	Unit Age
AB Brown 1	245	238.3	Coal	1979
AB Brown 2	245	223.1	Coal	1986
FB Culley 2	90	85.6	Coal	1966
FB Culley 3	270	263.2	Coal	1973
Warrick 4	150	132.2	Coal	1970
AB Brown 3	80	71.7	Gas	1991
AB Brown 4	80	72.7	Gas	2002
BAGS 2	65	57.6	Gas	1981
Northeast GT 1&2	20	18.9	Gas	1963 / 1964
Blackfoot	3	3 - N/A[19]	Landfill Gas	2009

5.1.1 Coal

The AB Brown Generating Station (ABB), located in Mt. Vernon, IN, consists of two coal fired units, each with an installed capacity of 245 MW. ABB Unit 1 began commercial operation in 1979, while ABB Unit 2 became operational in 1986.

Both AB Brown units are scrubbed for sulfur dioxide (SO_2) emissions, utilizing a dual-alkali flue gas desulfurization (FGD) process. The FGD systems were included as part of the original unit design and construction. Sulfur trioxide (SO_3) is removed via sodium bisulfite (SBS) injection systems installed on both units in 2015. ABB is also scrubbed for nitrogen oxides (NO_x) with selective catalytic reduction (SCR) systems having been installed on Unit 2 in 2004 and on Unit 1 in 2005. Mercury (Hg) removal is accomplished on both units as a co-benefit of SCR and FGD operations as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is

[19] The Blackfoot landfill gas generator is connected at the distribution level and is not part of the transmission connected generation network managed by MISO. Therefore, it is not assigned a MISO UCAP value.

captured via an electrostatic precipitator (ESP) on Unit 2. Unit 1 was upgraded to a fabric filter in 2004. The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

AB Brown Units 1 and 2 burn Illinois basin bituminous coal, which is mined in Knox County, IN and is delivered via rail.

The AB Brown plant site also has two natural gas turbine generators which are discussed in Section 5.1.2, Natural Gas.

The FB Culley Generating Station (FBC), located near Newburgh, IN, is a two unit, coal fired facility. FBC Unit 2 has an installed generating capacity of 90 MW and came online in 1966, while FBC Unit 3 has an installed capacity of 270 MW and became operational in 1973.

FBC is scrubbed for sulfur dioxide (SO_2) emissions, utilizing a forced oxidation flue gas desulfurization (FGD) process which is shared by both units and was retrofitted in 1994. The captured SO_2 is converted into synthetic gypsum within the system and, as part of Vectren's beneficial reuse program, is shipped, via barge, to a facility near New Orleans, LA where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed from both units via a dry sorbent injection (DSI) system installed in 2015. FBC Unit 3 is also scrubbed for nitrogen oxides (NO_x) with a selective catalytic reduction (SCR) system that was installed in 2003. NO_x control on FBC Unit 2 is through the use of low NO_x burners. Mercury (Hg) removal is accomplished on both units as a co-benefit of SCR & FGD operation as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is captured via an electrostatic precipitator (ESP) retrofitted on Unit 2 in 1972. Unit 3 was upgraded to a fabric filter for PM control in 2006. The PM that is captured, also known as fly ash, is part of Vectren's

beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

The FB Culley units burn Illinois basin bituminous coal, which is mined in Knox County, IN and delivered via truck.

Warrick Unit 4 (Warrick) located near Newburgh, IN is a coal fired unit operated and maintained by Alcoa Power Generating Inc. Vectren maintains 50% ownership of Warrick Unit 4. It has an installed 300 MW unit which began commercial operation in 1970. Vectren's 50% interest is equal to 150 MW.

Warrick Unit 4 is scrubbed for sulfur dioxide (SO_2) emissions, utilizing a forced oxidation flue gas desulfurization (FGD) process which was retrofitted in 2009. The captured SO_2 is converted into synthetic gypsum within the system, and (as part of Vectren's beneficial reuse program) is shipped via truck to a facility near Shoals, IN where it is used in the manufacture of drywall. Sulfur trioxide (SO_3) is removed via a dry sorbent injection (DSI) system installed in 2010. Unit 4 is also scrubbed for nitrogen oxides (NO_X) with a selective catalytic reduction (SCR) system which was retrofitted in 2004. Mercury (Hg) removal is accomplished as a co-benefit of SCR and FGD operation as well as through the addition of organosulfide injection systems installed in 2015. Particulate matter (PM) is captured via an electrostatic precipitator (ESP). The PM that is captured, also known as fly ash, is part of Vectren's beneficial reuse program and is shipped, via barge, to a facility near St. Louis, MO where it is used in the manufacture of cement.

Warrick Unit 4 burns Illinois basin bituminous coal. Vectren purchases coal for its share of Warrick Unit 4, which is mined in Knox County, IN and is delivered by truck.

5.1.2 Natural Gas

The AB Brown Generating Station (ABB) located near Mt. Vernon, IN has two natural gas fired simple cycle gas turbine (SCGT) peaking units. Each has an installed capacity of 80 MW. ABB Unit 3 began commercial operation in 1991, while ABB Unit 4 became operational in 2002.

Broadway Avenue Generating Station (BAGS) located in Evansville, IN consists of two gas fired SCGT peaking units. BAGS Unit 1 became operational in 1972 and had an installed capacity rating of 50 MW. This unit has been mothballed and is earmarked for retirement. BAGS Unit 1 is not currently included in Vectren's capacity analysis. BAGS Unit 2 began operation in 1981 and has an installed capacity of 65 MW.

The Northeast Gas Turbine (NEGT 1) facility located in Evansville, IN consists of two natural gas fired peaking units. NEGT 1 began commercial operation in 1963 and has an installed capacity of 10 MW. NEGT 2 became operational in 1964 and also has an installed capacity of 10 MW.

5.1.3 Renewables

The Blackfoot Clean Energy Facility located in Winslow, IN is a base load facility consisting of two internal combustion (IC) landfill methane gas fired units. Blackfoot Units 1 & 2 became operational in 2009 and are capable of producing 1.5 MW each.

5.1.4 DSM

5.1.4.1 INTRODUCTION

Vectren utilizes a portfolio of DSM programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. Vectren's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years.

Since 1992, Vectren has operated a Direct Load Control (DLC) program called Summer Cycler that reduces residential and small commercial air-conditioning and water heating electricity loads during summer peak hours. A description of the program is included below. While this technology can still be reliably counted on to help lower demand for electricity at times of peak load, this aging technology will be phased out over time. Vectren's Summer Cycler program has served Vectren and its customers well for more than two decades, but emerging technology is now making the program obsolete.

Furthermore, between 2010 and 2015, Vectren's DSM programs reduced demand by approximately 44,000 kW and provided annual incremental gross energy savings of approximately 217,000,000 kWh.

The table below outlines the estimated program penetration on a yearly basis since Vectren programs began in 2010. Gross cumulative savings, less opt out savings, are shown as a percent of eligible retail sales. Note that historical DSM savings are implicitly included in the load forecast as these savings are embedded in the historical sales data.

Figure 5.2 – Gross Cumulative Savings

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh) - Less Opt Out Savings	Percent of Sales Achieved (Cumulative)
2010	5,616.87	2.52	0.04%
2011	5,594.84	18.30	0.33%
2012	5,464.75	62.29	1.14%
2013	5,459.11	122.06	2.24%
2014[20]	3,498.69	176.74	5.05%
2015	3,223.81	217.25	6.74%

[20] Cumulative savings as a percent of eligible sales saw a higher increase from 2013 to 2014 due to the SB 340's opt-out provision. In 2014, Vectren's eligible sales decreased at a higher rate than achieved savings. For this reason, Vectren achieved higher savings as a percent of eligible sales.

5.1.4.2 2016-2017 Plan Overview

Current Energy Efficiency Programs

On March 23, 2016, the IURC issued an Order approving Vectren's 2016-2017 Energy Efficiency Plan (2016-2017 EE Plan) pursuant to Section 10. Consistent with the 2014 IRP, the framework for the 2016-2017 EE Plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% of eligible load. Below is a listing of residential and commercial & industrial programs offered in 2016-2017. For full program descriptions including the customer class, end use of each program, and participant incentives provided by the programs, please refer to the 2016-2017 EE Plan detail found in the Technical Appendix Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan.

Residential Programs

- Residential Lighting
- Home Energy Assessments and Weatherization
- Income Qualified Weatherization
- Appliance Recycling
- Energy Efficient Schools
- Residential Efficient Products
- Residential New Construction
- Multi-Family Direct Install
- Residential Behavior Savings
- Residential Smart Thermostat Demand Response

Commercial & Industrial Programs

- Small Business Direct Install
- Commercial & Industrial Prescriptive Rebates
- Commercial & Industrial New Construction
- Commercial & Industrial Custom
- Conservation Voltage Reduction (CVR)

The 2016-2017 plan was included as a resource in the resource optimization model (Strategist) and has an assumed average measure life of 10 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in Technical Appendix 10.3 DSM Appendix.

Figure 5.3 – 2016-2017 Energy Efficiency Plan Savings

	2016*		2017**	
Sector	Net MWh Energy Savings	Net MW Demand Savings	Net MWh Energy Savings	Net MW Demand Savings
Residential	18,072	4.8	16,332	3.8
Commercial & Industrial	16,474	2.4	15,864	2.4
Total	34,546	7.3	32,196	6.2

*2016 Operating Plan used for 2016
**2016-2017 Filed Plan used for 2017

5.1.5 Demand Response

Vectren's tariff currently includes two active demand response programs: the Direct Load Control and interruptible options for larger customers. Demand response programs allow Vectren to curtail load for reliability purposes. Vectren's tariff also includes a MISO demand response tariff, in which no customers are currently enrolled given the absence of an active demand response program within the MISO market at this time. For purposes of modeling DSM for the IRP, Vectren assumed an active MISO demand response market beginning in 2020.

5.1.5.1 Current DLC (Summer Cycler)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, electric water heating, and pool pumps through radio controlled load management receivers (LMR). Under the program, Vectren compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. Vectren can initiate a load control event for several reasons, including: to balance utility system supply and demand, to alleviate

transmission or distribution constraints, or to respond to load curtailment requests from the Midcontinent Independent Transmission System Operator, Inc. (MISO).

Vectren manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. Vectren also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

Cadmus predicts the DLC Program is capable of generating approximately 19.3 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control. As of May 2016, Vectren's DLC Program included over 23,000 customers with a combined total of approximately 31,000 switches. Note that a customer may have more than one switch at a residence or business.

5.1.5.2 Current Interruptible Load

Vectren makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. The five customers currently participating provide for a total demand reduction of 35 MW.

5.1.5.3 Smart Thermostats

Pursuant to the IURC approved DSM plan in 2016, Vectren conducted a field study designed to analyze the different approaches of DR that are available through smart thermostats. Between the months of April and May, Vectren installed approximately 2,000 smart thermostats (1,000 Honeywell and 1,000 Nest) in customer homes. Vectren leveraged these thermostats to manage DR events during the summer in an effort to evaluate the reduction in peak system loads. These smart devices, which reside on the customer's side of the electric meter, are connected to Wi-Fi and reside on the customer's side of the electric meter and are used to communicate with customer's air

conditioning systems. The program provides Vectren with increased customer contact opportunities and the ability to facilitate customers' shift of their energy usage to reduce peak system loads. In 2017, Vectren will work with an independent evaluator to conduct a billing analysis to measure the effectiveness of the program, including specific performance of the Nest and Honeywell products.

If the program is successful, Vectren will pursue significant expansion in 2018 and beyond, using the technology that best serves its customers' needs. If approved by the Commission, Vectren anticipates replacing DLC switches with smart thermostats over time; indications are the benefits associated with this emerging technology far outweigh the benefits associated with DLC switches.

5.1.5.4 Other Innovative Rate Design

Vectren periodically evaluates alternative rate design and its ability to implement new options as the energy marketplace continues to evolve. Proposals that provide variable energy pricing based on how electric prices change throughout the day (Time of Use rates) and other pricing alternatives may be considered at such time as the required technology upgrades are implemented.

5.2 POTENTIAL FUTURE OPTIONS MODELING ASSUMPTIONS

5.2.1 Coal Technologies

Coal power plants are characterized by pulverizing coal, then burning the coal in a boiler to create heat. The heat from the boiler is then used to turn water into high pressure steam which is used to turn the turbine causing the generator to create electricity.

Another type of coal technology evaluated was the Integrated Gasification Combined Cycle (IGCC). IGCC produces a low calorific value syngas (synthetic natural gas) from coal or solid waste which can be fired in a combined cycle power plant. The gasification

process itself is a proven technology used extensively for chemical production of goods such as ammonia for fertilizer. See Figure 5.4 for further details on the coal technologies evaluated.

Figure 5.4 – Coal Technologies

Coal			
Operating Characteristics and Estimated Costs	**Supercritical Pulverized Coal 500 MW**	**Supercritical Pulverized Coal 750 MW**	**2x1 Integrated Gasification CC**
Base Load Net Output (MW)	425	637.5	525
Base Load Net Heat Rate (HHV Btu/kWh)	10,500	10,200	10,500
Base Project Costs (2015$/kW)	$5,570	$5,080	$3,928
Fixed O&M Costs (2015$/kW-year)	$31.90	$21.20	$36.30

5.2.2 Natural Gas Technologies

5.2.2.1 Simple Cycle Gas Turbines

Simple cycle gas turbines (SCGT) utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies, and relatively low capital costs. See Figure 5.5 for further details on the simple cycle gas turbine technologies evaluated.

Figure 5.5 – Simple Cycle Gas Turbine Technologies

Simple Cycle Gas Turbines				
Operating Characteristics and Estimated Costs	**1xLM6000 SCGT**	**1xLMS100 SCGT**	**1xE-Class SCGT**	**1xF-Class SCGT**
Base Load Net Output (MW)	43.4	99.5	90.1	219.8
Base Load Net Heat Rate (HHV Btu/kWh)	9,210	8,840	11,310	9,750
Base Project Costs (2015$/kW)	$1,880	$1,430	$1,230	$650
Fixed O&M Costs (2015$/kW-year)	$26.57	$11.72	$15.83	$7.08

5.2.2.2 Combined Cycle Gas Turbines

Combined cycle gas turbines (CCGT) utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery

steam generator (HRSG). This steam is then used to drive the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions.

For this assessment, a 1x1, 2x1, and 3x1 power block, as shown in Figure 5.6, were evaluated with General Electric (GE) 7F-5 turbines as representative CCGT technologies. A 1x1 CCGT has one gas or steam turbine coupled with one HRSG. A 2x1 has two gas or steam turbines coupled with one HRSG. A 3x1 follows the same pattern. The 2x1 CCGT F class technology was considered for both .04 and .05 versions. The .05 technology is GE's most recent F class offering. See Figure 5.6 for further details on the combined cycle gas turbine technologies evaluated.

Figure 5.6 – Combined Cycle Gas Turbine Technologies

Combined Cycle Gas Turbines				
Operating Characteristics and Estimated Costs[21]	**1x1 7FA.05 CCGT (ABB)**	**2x1 7FA.04 CCGT (ABB)**	**2x1 7FA.05 CCGT (ABB)**	**3x1 7FA.05 CCGT (ABB)**
Duct-Firing	Fired	Fired	Fired	Fired
Base Load (24/7 Power) Net Output (MW)	343	579	690	1039
Incremental Duct-Fired (Peaking) Net Output (MW)	99	167	199	298
Base Load Net Heat Rate (HHV Btu/kWh)	6,590	6,650	6,540	6,520
Incremental Duct-Fired Heat Rate (HHV Btu/kWh)	8,460	8,580	8,450	8,460
Base Project Costs (2015$/Fired kW)	$840	$720	$640	$550
Fixed O&M Costs (2015$/Base Load kW-year)	$12.26	$8.89	$7.46	$5.95

A site selection study that examined Greenfield (potential new power plant sites) and compared Brownfield (existing power plant sites) can be found in Technical Appendix Confidential Attachment 5.2 CCGT Site Selection Report.

Vectren initiated studies to evaluate retrofit options that would repurpose existing coal fired generation assets to use natural gas.

[21] Combined cycle gas turbines are shown as fired configuration at AB Brown site for this table. Reference the Technology Assessment for additional details on duct-firing

5.2.2.3 Refuel Option

The conversion of existing coal fired boilers to burn natural gas instead of coal was studied. Detailed site specific studies were performed to determine costs, MW ratings and expected heat rates (efficiency), total natural gas fuel flow requirements, and projected emissions. More information on the refuel option can be found in Technical Appendix Confidential Attachment 1.2 Vectren Technology assessment Summary Table.

5.2.2.4 Repower Option

The conversion of a coal fired unit to a combined cycle gas turbine CCGT was studied. With a unit repower, the existing coal fired boiler and its associated auxiliary equipment would be decommissioned. The steam supply to the legacy steam turbine and electric generator would be accomplished by way of newly constructed heat recovery steam generators capturing heat from the exhaust gas of newly constructed combustion turbines, each of which would have shaft driven electric generators. Detailed site specific studies were performed to determine costs, MW ratings and expected heat rates (efficiency), total natural gas fuel flow requirements, and projected emissions. More information on the repower option can be found in Technical Appendix Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table.

5.2.2.5 Combined Heat and Power (CHP)

Combined Heat and Power (CHP), also known as cogeneration, provides both electricity and useful heating or cooling. CHP captures the benefits of heating or cooling, which is created as a byproduct of electricity production, and can be used to create hot water or steam. CHP is typically most efficient when produced close to the end user. See Figure 5.7 for further details on the CHP technologies evaluated.

Figure 5.7 – Combined Heat & Power Technologies

Combined Heat and Power (CHP)					
Operating Characteristics and Estimated Costs	**1 MW Microturbine**	**3 MW Combustion Turbine Generator**	**5 MW Combustion Turbine Generator**	**10 MW Combustion Turbine Generator**	**15 MW Combustion Turbine Generator**
Base Load Net Output (MW)	1.0	3.2	5.1	10.3	13.6
Base Load Net Heat Rate (HHV Btu/kWh)[1]	6,510	4,460	4,400	4,480	4,450
Base Project Costs (2015$/kW)	$4,746	$7,602	$5,637	$3,874	$2,975
Fixed O&M Costs (2015$/kW-year)	$180.30	$227.86	$172.28	$118.77	$99.55

[1]Heat rates are credited for fuel required to produce equivalent steam output.

CHP technical and operating considerations should include the following: customer electric load and thermal requirements inclusive of a detailed engineering and feasibility review. The matching of high load factor thermal load is key to CHP success. In most cases, electricity is considered the byproduct of the process. It is important to understand the variation in heat and electrical demand (demand profiles) as well as the infrastructure modifications within the customer's facility compared to utility connection.

For this screening process it was assumed that Vectren will own and operate a CHP facility. However, it should be noted that a CHP investment may require customers to own and operate internal electric equipment and/or construct significant electric distribution infrastructure. CHP must be mutually beneficial to the customer and Vectren. It is ultimately a customer decision. Upon review of potential customer sites, Vectren identified a market potential of approximately 30 MWs of matching steam and electric load in the Vectren South service territory. The CHP market potential study can be found in Technical Appendix Confidential Attachment 5.4 CHP Market Potential Study.

5.2.3 DSM

5.2.3.1 Background

In developing a resource plan that integrates demand side and supply side resources, it is incumbent for the energy company to provide the integrating process with a set of demand side (DSM) options that can be incorporated into the plan. This process aligns with IURC's proposed Rule 170IAC 4-7-6(b) which states:

> "An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers."

In addition, this process aligns with Senate Enrolled Act (SEA) 412 which requires that energy efficiency goals be consistent with an electricity supplier's IRP. Taken together, these jointly supportive requirements direct the energy company to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the energy company should be determined through the IRP process.

Given that, two questions must be addressed. One, how much DSM should be made available as resource options for selection by the IRP process? And two, how does one project the cost of the DSM resource options over a 20-year horizon and increasing market penetration?

5.2.3.2 DSM Availability

Obviously, at one extreme, one could argue that 100% of retail sales of an energy company could be made available for selection as a DSM resource. However, that is not practical as some energy must be consumed in the course of economic activity. At

the other extreme, one could argue that no DSM resource options are required as consumers make their own decisions on the tradeoffs between consumption of energy and investment in more efficient technologies. The result of those decisions would already be reflected in the Company's projection of electric loads.

However, there are barriers to the adoption of more efficient energy using technologies that can be overcome through the implementation of targeted energy company energy efficiency programs. Energy efficiency programs, as marketing programs, encourage customers to adopt higher levels of efficiency earlier than would happen naturally, basically advancing the timing of the energy efficiency. Guidance on the appropriate level of energy efficiency to be made available to the IRP process can be obtained from a market potential study. The Company's market potential study[22] found a Technical Potential of 11%, an Economic Potential of 8.2%, an Achievable High Potential of 6.2%, and an Achievable Low Potential of 3.5%. However, this is only for the years 2015 through 2019.

Another source of information on market potential may be found in a study conducted by the Electric Power Research Institute (EPRI)[23]. This study estimated the potential for the period 2013 through 2035 for the nation as well as selected regions including the Midwest. For the Midwest region, for the full period to the year 2035, the study found a Technical Potential of 23.7%, an Economic Potential of 13.8%, a High Achievable Potential of 11.1%, and an Achievable Potential of 8.9%.

Technical potential is the maximum energy efficiency available, assuming that cost and market adoption of a technology are not a barrier. Economic potential is the amount of energy efficiency that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which

[22] ELECTRIC DEMAND SIDE MANAGEMENT: MARKET POTENTIAL STUDY AND ACTION PLAN, April 2013 prepared by EnerNOC Utility Solutions Consulting.
[23] U.S. Energy Efficiency Potential Through 2035. 1025477 Final Report, April 2014.

compares the lifetime energy and capacity benefits to the incremental cost of the measure. This achievable potential is the amount of energy efficiency that is cost effective and can be achieved given customer preferences. Not all customers will adopt a given technology. For example, CFL light bulbs have been cost effective for many years; however, some people chose not to adopt them for aesthetic reasons. This provides some guidance on the types of potential that the Company could consider for inclusion in its set of DSM resource options.

However, one must consider the impact on these estimates from the fact that larger customers may opt-out of participation in Vectren's energy efficiency programs. As a result of customer opt-outs, 41% of retail sales are not available for consideration in development of DSM resource options. In addition, another adjustment to the available market potential should be taken to capture the level of energy efficiency (EE) impacts expected to be already achieved in the 2013 to 2016 period (when industrial customers were allowed to begin opting out) as represented in the following table.

Figure 5.8 – Vectren Historical Energy Efficiency Impacts

Year	Eligible Retail Sales (GWh)	Gross Incremental Savings (GWh) - Less Opt Out Savings	Gross Cumulative Savings (GWh) - Less Opt Out Savings	Incremental DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales	Cumulative DSM Savings (less opt-out) as a Percent of Eligible Sales Since 2013
2010	5,616.87	2.52	2.52	0.04%	0.04%	
2011	5,594.84	15.78	18.30	0.28%	0.33%	
2012	5,464.75	43.99	62.29	0.81%	1.14%	
2013	5,479.11	59.77	122.06	1.09%	2.23%	1.09%
2014	3,498.69	54.68	176.74	1.56%	5.05%	3.27%
2015	3,223.81	40.51	217.25	1.26%	6.74%	4.81%
Est2016	3,611.51	42.32	259.57	1.17%	7.19%	5.46%

This implies that the EPRI market potential estimates should be adjusted down to reflect the portion that has already been achieved. Using a conservative estimate of 5% of the

potential already achieved, the remaining Technical Potential is estimated to be 18.7%, Economic Potential is 8.8%, High Achievable Potential is 6.1%, and Achievable Potential is 3.9%.

While some may contend that the full technical potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic. Rather, the potential should reflect some consideration of achievability. This can be estimated by taking the ratio of the achievable percentages to the technical potential percentage and applying that to the remaining estimate of technical potential percentage. This means that 46.8% (11.1%/23.7%) of the technical potential would be considered as the remaining High Achievable Technical Potential or 8.8% of retail sales (e.g., 0.468 x 18.7%). Similarly, 37.6% of the technical potential would be considered as the remaining Achievable Technical Potential or 7.0% of retail sales.

The foregoing provides guidance on the level of DSM resource options that should be considered in the IRP analytical process as well as the maximum levels that seem reasonable at a high level.

For the initial performance of the IRP analysis, Vectren chose to make up to 2% of retail sales as DSM resource options available for selection in the IRP process for each year of the 20 year planning horizon. This represents almost 40% of retail sales, far above any reasonable estimate of even technical market potential. The 2% applies to the level of retail sales after reduction for the level of load that has opted out. To facilitate the IRP resource selection process, the 2% of retail sales was broken into 8 blocks of 0.25% each. Taking this over the 20 year horizon means that over 150 incremental blocks of 0.25% each were available to be selected in the IRP process[24]. From this structure, Vectren expects that the appropriate IRP determined cost-effective level of

[24] For the first two years of the planning horizon, 2016 and 2017, the energy efficiency impacts are based upon the plan approved in Cause No. 44645.

EE would be identified. This process should provide substantial insight on the cost-effective level of energy efficiency. The following table represents the structure and the sizes of the blocks.

Figure 5.9 – DSM Resource Options Net of Free Riders

Year	Eligible GWh Conservation Savings	Percent of Eligible Sales Potential	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016										
2017	3,493									
2018	3,525	2.0%	6.986	6.986	6.986	6.986	6.986	6.986	6.986	6.986
2019	3,545	2.0%	7.050	7.050	7.050	7.050	7.050	7.050	7.050	7.050
2020	3,571	2.0%	7.089	7.089	7.089	7.089	7.089	7.089	7.089	7.089
2021	3,577	2.0%	7.141	7.141	7.141	7.141	7.141	7.141	7.141	7.141
2022	3,594	2.0%	7.154	7.154	7.154	7.154	7.154	7.154	7.154	7.154
2023	3,613	2.0%	7.188	7.188	7.188	7.188	7.188	7.188	7.188	7.188
2024	3,640	2.0%	7.227	7.227	7.227	7.227	7.227	7.227	7.227	7.227
2025	3,654	2.0%	7.281	7.281	7.281	7.281	7.281	7.281	7.281	7.281
2026	3,672	2.0%	7.309	7.309	7.309	7.309	7.309	7.309	7.309	7.309
2027	3,692	2.0%	7.344	7.344	7.344	7.344	7.344	7.344	7.344	7.344
2028	3,721	2.0%	7.384	7.384	7.384	7.384	7.384	7.384	7.384	7.384
2029	3,739	2.0%	7.442	7.442	7.442	7.442	7.442	7.442	7.442	7.442
2030	3,755	2.0%	7.477	7.477	7.477	7.477	7.477	7.477	7.477	7.477
2031	3,772	2.0%	7.511	7.511	7.511	7.511	7.511	7.511	7.511	7.511
2032	3,796	2.0%	7.543	7.543	7.543	7.543	7.543	7.543	7.543	7.543
2033	3,810	2.0%	7.592	7.592	7.592	7.592	7.592	7.592	7.592	7.592
2034	3,831	2.0%	7.620	7.620	7.620	7.620	7.620	7.620	7.620	7.620
2035	3,850	2.0%	7.663	7.663	7.663	7.663	7.663	7.663	7.663	7.663
2036	3,876	2.0%	7.701	7.701	7.701	7.701	7.701	7.701	7.701	7.701

The component programs for the blocks are assumed to initially be those approved in Cause No. 44645 and previously described in Section 5.1.4, DSM. For the first two years of the planning horizon (2016 and 2017), it is assumed that the current set of approved programs are being implemented. However, it is expected that the nature of the programs in the blocks may change over time as energy efficiency technology changes.

No minimum level of energy efficiency impacts have been locked in for the planning process. The table provides 0.25% blocks of net impacts which already reflects a 20% adjustment for free riders. Free riders represent those participants that would have implemented the energy efficiency technology without the energy company program.

5.2.3.3 DSM Resource Cost – Base Case

Projecting the cost of the DSM programs that are expected to achieve a 40% level of energy efficiency (EE) over a long period represents a challenge. As a starting point, the cost of the energy efficiency programs approved in Cause No. 44645 is used for the 2017 DSM resource options. The Company's EE portfolio being implemented in 2016 is designed to achieve approximately 36,000 MWh impacts on a net of free-rider basis at a cost of $0.20 per first year kWh[25] ($.03322 per kWh on a levelized basis). Through 2015, the Company has already achieved a reduction of approximately 7% of available 2017 retail sales (total retail sales reduced for opt-outs)[26]. On a net of free-rider basis, the 2016 plan is designed to achieve an additional 1% of available retail sales.

As discussed above, in an effort to allow the IRP model to inform the Company on the cost-effective level of EE to pursue in the resource plan, the Company has provided the IRP model with the ability to select from 8 blocks of EE impacts each year where each block represents 0.25% of retail sales. This represents a possible additional 2% of available retail sales that could be selected each year from 2018 through 2036.

On a cumulative basis, this means that almost 40% of available retail sales could be selected by the IRP process. This is in addition to the approximate 7% already achieved through past EE efforts. Vectren is not aware of any national or regional EE market potential study with a higher estimate of EE potential. In order to identify the cost-effective level of EE in the IRP process, it is imperative that Vectren develop

[25] This value is estimated using the total cost of the program and dividing by the first year of EE savings.
[26] As previously mentioned, the Company has achieved a 3% reduction in total retail sales over the period 2013 through 2015.

estimates of the cost of EE achievement that reflect how the costs could change as EE market penetration increases.

To this end, Vectren retained Dr. Richard Stevie, VP of Forecasting with Integral Analytics, Inc., to provide insights on how the cost to achieve an increment of EE could change as the cumulative EE market penetration rises. Dr. Stevie's recommendation is based upon his research into the relationship between spending on EE programs and the level of first year impacts achieved through the implementation of the EE programs as well as the cumulative level of EE impacts. The research relies upon EE cost and impact data collected through Form 861 by the Energy Information Administration (EIA). A copy of the research study is provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency Programs. The study found that EE program costs per kWh increase as the cumulative penetration of EE increases, as measured by the percent of retail sales. The primary focus of the research was to examine if and to what extent the program cost of EE changes as the available supply (i.e., retail sales) of EE is consumed through implementation of EE programs. Based upon this research and Vectren's projected level of EE available for selection by the IRP process, Dr. Stevie developed a projected rate of growth in the cost of EE for the first four blocks which cumulatively represent 1% of eligible retail sales each year. This growth rate was applied to each of the first four 0.25% blocks.

The growth rate was developed from two separate econometric models of the EIA data as described in the study provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency Programs. The results from the two models were averaged to produce a growth rate in cost of 4.12% per 1% of retail sales achievement or 1.04% per 0.25% EE block.

With this first 1% of retail sales, Vectren is planning to achieve an amount of energy efficiency that exceeds an expected high achievable level over the next 20 years. As a result, it is assumed that the second 1% of retail sales must occur at a higher marketing

cost than the first 1% of retail sales. In other words, the methodology is that for the first 1%, for the full planning period, Vectren is achieving actually more than what it should reasonably expect to achieve in the market place. The effort being undertaken is as if Vectren were achieving the full 1% for 20 years or 20% of the market at a base level of cost. To get the next 1%, one has to step up to a higher marketing cost that assumes the first 1% has already been achieved. The next 1% is incremental to the first 1%. It is assumed that Vectren will have to dramatically expand its marketing effort to essentially double the annual impact achievement. This would involve expanded advertising and possibly in person contact to get customers to take action. Essentially the second 1% has to be more expensive, not cheaper, than the first 1%.

As a result, the starting cost for the second 1% of blocks is assumed to be the ending cost (in real dollars) for the first 1%. Then, a different growth rate is applied for the remaining set of four 0.25% blocks available each, or the next 1% of retail sales available for selection. The process of computing the applicable growth rate was similar to that of the first 1%. This resulted in a growth rate of 1.72% per additional 1% of retail sales impacts or 0.43% per 0.25% block. So, this assumes that once the first four blocks have been selected in a year by the IRP, the cost increases first to the cost of the last block of the 1% of retail sales and then by 0.43% per 0.25% block for the 5th to 8th blocks. These growth rates form the basis for projecting how the block costs change for all of the blocks available for selection by the IRP process. The lower growth rate was applied to the second 1% of retail sales (blocks 5 to 8) to allow for economy of operation within a given year, while the higher growth rate was applied to the first 1% of retail sales to try to capture the impact on cost over time. The following table provides the estimated levelized costs used for all of the blocks.

Figure 5.10 – Base Case Cost per kWh[27]

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03356	$0.03391	$0.03426	$0.07811	$0.07844	$0.07878	$0.07911
2017	$0.03462	$0.03498	$0.03534	$0.03570	$0.07945	$0.07979	$0.08013	$0.08048
2018	$0.03607	$0.03645	$0.03682	$0.03721	$0.08082	$0.08117	$0.08151	$0.08186
2019	$0.03759	$0.03798	$0.03837	$0.03877	$0.08221	$0.08256	$0.08292	$0.08327
2020	$0.03917	$0.03958	$0.03999	$0.04040	$0.08363	$0.08398	$0.08434	$0.08470
2021	$0.04082	$0.04124	$0.04167	$0.04210	$0.08507	$0.08543	$0.08579	$0.08616
2022	$0.04254	$0.04298	$0.04342	$0.04387	$0.08653	$0.08690	$0.08727	$0.08764
2023	$0.04433	$0.04478	$0.04525	$0.04572	$0.08802	$0.08840	$0.08877	$0.08915
2024	$0.04619	$0.04667	$0.04715	$0.04764	$0.08953	$0.08992	$0.09030	$0.09069
2025	$0.04813	$0.04863	$0.04914	$0.04964	$0.09108	$0.09146	$0.09186	$0.09225
2026	$0.05016	$0.05068	$0.05120	$0.05173	$0.09264	$0.09304	$0.09344	$0.09384
2027	$0.05227	$0.05281	$0.05336	$0.05391	$0.09424	$0.09464	$0.09504	$0.09545
2028	$0.05447	$0.05503	$0.05560	$0.05618	$0.09586	$0.09627	$0.09668	$0.09709
2029	$0.05676	$0.05734	$0.05794	$0.05854	$0.09751	$0.09793	$0.09834	$0.09876
2030	$0.05914	$0.05976	$0.06038	$0.06100	$0.09919	$0.09961	$0.10004	$0.10046
2031	$0.06163	$0.06227	$0.06292	$0.06357	$0.10089	$0.10133	$0.10176	$0.10219
2032	$0.06422	$0.06489	$0.06556	$0.06624	$0.10263	$0.10307	$0.10351	$0.10395
2033	$0.06693	$0.06762	$0.06832	$0.06903	$0.10440	$0.10484	$0.10529	$0.10574
2034	$0.06974	$0.07046	$0.07119	$0.07193	$0.10619	$0.10665	$0.10710	$0.10756
2035	$0.07268	$0.07343	$0.07419	$0.07496	$0.10802	$0.10848	$0.10895	$0.10941
2036	$0.07573	$0.07652	$0.07731	$0.07811	$0.10988	$0.11035	$0.11082	$0.11130

The detailed calculation of the growth rates is provided in Technical Appendix Attachment 5.3 Cost of Energy Efficiency.

5.2.3.4 DSM Resource Cost - Scenario Analysis

The previous discussion provided the Base Case projection of DSM resource costs. However, DSM resource costs are a key component to the integration of DSM into the resource plan. Given the uncertainty around these costs, especially considering a 20 year implementation period, alternate views of the costs should be examined in the context of the scenario and stochastic risk analyses. Only time and actual experience with increases in DSM market penetration will provide better guidance on these cost projections.

[27] Costs included in the risk analysis modeling

To that end, high and low DSM resource cost trajectories were developed using the estimated standard errors of the model coefficients used in the development of the Base Case cost projection. These high and low cost trajectories were created by applying plus and minus one standard error to the model coefficients.[28] This produces alternate DSM resource cost growth rates summarized in the following table.

Figure 5.11 – DSM Resource Cost Growth Rates

Sets of Four Blocks	Minus One Standard Deviation	Base Case	Plus One Standard Deviation
First 1%	0.85%	1.04%	1.22%
Second 1%	0.35%	0.43%	0.51%

Applying these alternate growth rates produces the following high and low tables of projected DSM resource costs.

[28] Using the model coefficients and standard errors from the two econometric models referenced in Dr. Stevie's research, the coefficient range is developed by adding the standard error to or subtracting it from the coefficient estimate. For the first model, the coefficient is .278 with a standard error of .084. For the second model, the coefficient is .897 with a standard error of .131.

Figure 5.12 – High Case Cost per kWh: Plus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03363	$0.03404	$0.03445	$0.09095	$0.09141	$0.09187	$0.09233
2017	$0.03487	$0.03530	$0.03573	$0.03617	$0.09280	$0.09327	$0.09374	$0.09421
2018	$0.03661	$0.03705	$0.03751	$0.03796	$0.09469	$0.09517	$0.09565	$0.09613
2019	$0.03843	$0.03890	$0.03937	$0.03985	$0.09662	$0.09710	$0.09759	$0.09809
2020	$0.04034	$0.04083	$0.04133	$0.04183	$0.09858	$0.09908	$0.09958	$0.10008
2021	$0.04234	$0.04286	$0.04338	$0.04391	$0.10059	$0.10110	$0.10161	$0.10212
2022	$0.04445	$0.04499	$0.04554	$0.04610	$0.10264	$0.10316	$0.10368	$0.10420
2023	$0.04666	$0.04723	$0.04781	$0.04839	$0.10473	$0.10526	$0.10579	$0.10632
2024	$0.04898	$0.04958	$0.05018	$0.05080	$0.10686	$0.10740	$0.10794	$0.10849
2025	$0.05142	$0.05205	$0.05268	$0.05332	$0.10904	$0.10959	$0.11014	$0.11070
2026	$0.05397	$0.05463	$0.05530	$0.05598	$0.11126	$0.11182	$0.11238	$0.11295
2027	$0.05666	$0.05735	$0.05805	$0.05876	$0.11352	$0.11409	$0.11467	$0.11525
2028	$0.05948	$0.06020	$0.06094	$0.06168	$0.11583	$0.11642	$0.11700	$0.11760
2029	$0.06243	$0.06320	$0.06397	$0.06475	$0.11819	$0.11879	$0.11939	$0.11999
2030	$0.06554	$0.06634	$0.06715	$0.06797	$0.12060	$0.12121	$0.12182	$0.12243
2031	$0.06880	$0.06964	$0.07049	$0.07135	$0.12305	$0.12367	$0.12430	$0.12493
2032	$0.07222	$0.07310	$0.07400	$0.07490	$0.12556	$0.12619	$0.12683	$0.12747
2033	$0.07581	$0.07674	$0.07768	$0.07862	$0.12811	$0.12876	$0.12941	$0.13006
2034	$0.07958	$0.08055	$0.08154	$0.08253	$0.13072	$0.13138	$0.13205	$0.13271
2035	$0.08354	$0.08456	$0.08559	$0.08664	$0.13338	$0.13406	$0.13473	$0.13541
2036	$0.08770	$0.08877	$0.08985	$0.09095	$0.13610	$0.13679	$0.13748	$0.13817

Figure 5.13 – Low Case Cost Per kWh: Minus One Standard Deviation

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8
2016	$0.03322	$0.03350	$0.03379	$0.03407	$0.06700	$0.06723	$0.06747	$0.06770
2017	$0.03436	$0.03465	$0.03495	$0.03524	$0.06794	$0.06818	$0.06841	$0.06865
2018	$0.03554	$0.03585	$0.03615	$0.03646	$0.06889	$0.06913	$0.06938	$0.06962
2019	$0.03677	$0.03708	$0.03739	$0.03771	$0.06986	$0.07011	$0.07035	$0.07060
2020	$0.03803	$0.03835	$0.03868	$0.03901	$0.07084	$0.07109	$0.07134	$0.07159
2021	$0.03934	$0.03967	$0.04001	$0.04035	$0.07184	$0.07209	$0.07234	$0.07260
2022	$0.04069	$0.04104	$0.04138	$0.04174	$0.07285	$0.07311	$0.07336	$0.07362
2023	$0.04209	$0.04245	$0.04281	$0.04317	$0.07388	$0.07413	$0.07439	$0.07465
2024	$0.04354	$0.04391	$0.04428	$0.04465	$0.07491	$0.07518	$0.07544	$0.07570
2025	$0.04503	$0.04542	$0.04580	$0.04619	$0.07597	$0.07623	$0.07650	$0.07677
2026	$0.04658	$0.04698	$0.04738	$0.04778	$0.07704	$0.07731	$0.07758	$0.07785
2027	$0.04818	$0.04859	$0.04901	$0.04942	$0.07812	$0.07839	$0.07867	$0.07894
2028	$0.04984	$0.05026	$0.05069	$0.05112	$0.07922	$0.07950	$0.07977	$0.08005
2029	$0.05155	$0.05199	$0.05243	$0.05288	$0.08033	$0.08061	$0.08089	$0.08118
2030	$0.05333	$0.05378	$0.05424	$0.05470	$0.08146	$0.08175	$0.08203	$0.08232
2031	$0.05516	$0.05563	$0.05610	$0.05658	$0.08261	$0.08290	$0.08319	$0.08348
2032	$0.05706	$0.05754	$0.05803	$0.05852	$0.08377	$0.08406	$0.08436	$0.08465
2033	$0.05902	$0.05952	$0.06003	$0.06053	$0.08495	$0.08524	$0.08554	$0.08584
2034	$0.06105	$0.06157	$0.06209	$0.06262	$0.08614	$0.08644	$0.08675	$0.08705
2035	$0.06315	$0.06368	$0.06422	$0.06477	$0.08735	$0.08766	$0.08796	$0.08827
2036	$0.06532	$0.06587	$0.06643	$0.06700	$0.08858	$0.08889	$0.08920	$0.08951

These cost projections were incorporated into the scenario analyses. The selection of a high or low cost projection depends upon the nature or characteristics of each scenario. Expected direction of power costs is assumed to be one of the key drivers in deciding which of the cost projections should be used in a given scenario.

Scenario 1, The High Regulatory Scenario, is characterized by a heavier reliance on regulations such as the Clean Power Plan (CPP) as well as other potential future regulations focused on reducing carbon emissions. In conjunction with these regulations, it is expected that more stringent codes and standards would be implemented to promote installation of more energy efficient equipment. The stricter efficiency codes and standards will likely shrink the available market potential for energy

company DSM programs, which could make it more difficult to market DSM resources. As a result, the high DSM resource cost projection is employed for this scenario.

Under the Low Regulatory Scenario, it is expected that with a reduced regulatory environment, there would be greater economic growth and thus a larger market for offering DSM programs. The lower regulatory environment could make it easier to market DSM resources. As a result, the low DSM resource cost projection is employed in this scenario.

The High Technology Scenario is characterized by significant advances in solar, wind, and energy storage technologies as well as advances in EE technologies. In addition, it is expected that newer technologies could improve marketing efficiency that makes it easier to attract DSM program participants. As a result, the low DSM resource cost projection is employed for this scenario.

The High Economy/Market Scenario sees faster economic growth which leads to higher growth in energy usage, in the absence of faster technology development. The growth in energy usage will make DSM resources more attractive and cost-effective for program participants. As a result, the low DSM resource cost projection is employed for this scenario.

Under the Low Economy/Market Scenario, the economy is sluggish which keeps load growth low. It is expected that power prices would increase at a slower rate which could make it more difficult to market DSM resources. As a result, the high DSM resource cost projection is employed in this scenario.

Incorporating alternate views of DSM resource costs into the IRP planning process provides a better view on the robustness of the final DSM resource selection.

5.2.3.5 Summary

This DSM Resource process provides EE savings and cost values for over 150 blocks of DSM resources representing almost 40% of available retail sales for potential selection by the IRP analytical model. This level of DSM resource options, exceeding estimates of Technical Potential, provides enough flexibility to the IRP model for identifying and selecting a DSM plan consistent with the IURC and legislative objectives. However, given that there is a potential to exceed the estimate of Technical Potential, adjusted for past impacts already obtained and for achievability, the results of the IRP analytical process need to be checked to ensure that the resulting level of DSM selected is ultimately and practically viable.

5.2.3.6 DSM Planning Process

One of the key objectives of the IRP is to "provide all customers with a reliable supply of energy at the lowest reasonable cost." The level of DSM to be offered in Vectren's service territory is an important outcome of the IRP process. The IRP should determine the appropriate level of DSM to include in the preferred resource plan. However, for Vectren, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 2-3 years Vectren engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to test the cost effectiveness of the programs.

5.2.3.7 Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy savings of the measure, life of the measure, implementation costs, administrative costs, incremental costs to the participant of the

high efficiency measure, and escalation rates and discount rates. Vectren considers the results of each test and ensures that the portfolio passes the Total Resource Cost (TRC) test as it includes the total costs and benefits to both the energy company and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test ("UCT")
- Total Resource Cost Test ("TRC")

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

Figure 5.14 – Vectren Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

The Participant Cost Test shows the value of the program from the perspective of the energy company's customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.
The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The Total Resource Cost (TRC) Test shows the combined perspective of the energy company and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to energy company programs and participant costs. In completing the tests listed above, Vectren used 10.09% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on April 27, 2011 in Cause No. 43839.

5.2.4 Demand Response

Demand Response (DR) represents curtailment or reduction to end user electrical consumption based on market or operator feedback. Feedback is typically driven by economic incentives or reliability concerns due to imbalances in supply and demand of electricity. DR is a broad category that can apply to a variety of both consumption technologies (i.e. air conditioner, irrigation, etc.) and customer classes (i.e. industrial, commercial, residential). DR is typically more cost effective with larger individual customer loads. See Figure 5.15 for further details on the DR technologies evaluated.

Figure 5.15 – Demand Response

Operating Characteristics and Estimated Costs	Demand Response
Base Load Net Output (MW)	4.0
Base Project Costs (2015$/kW)	$14.00
Fixed O&M Costs (2015$/kW-year)	$57.07

5.2.5 Renewables Technologies

5.2.5.1 Wind

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic, and hydroelectric.

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 5.16 for further details on the variety of wind technologies evaluated.

Figure 5.16 – Wind Renewables

Operating Characteristics and Estimated Costs	50 MW Wind (Indiana)	200 MW Wind (Indiana)
Base Load Net Output (MW)	50	200
Base Project Costs (2015$/kW)	$1,940	$1,680
Fixed O&M Costs (2015$/kW-year)	$45.00	$42.00

The production tax credit (PTC) is a tax credit per-kilowatt-hour (kWh) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the in-service date for all facilities placed in service after August 8, 2005. The tax credit is $0.015 per kWh in 1993 adjusted by inflation adjustment factor provided by the IRS and rounded to the nearest 0.1 cents. Vectren assumed 1.6% past 2016 IRS values, which was the general inflation used throughout the IRP. The tax credit is phased down by 20 percent per year for wind facilities commencing construction after December 31, 2016. The tax credit reduces from 100 percent for wind facilities commencing construction in 2016 and before, down to 40 percent for wind facilities commencing construction in 2019. See Figure 5.17 below for the percent of production tax credit. For purposes of the IRP, Vectren applied the PTC as if the commence construction was one year prior to the commercial operation date.

Figure 5.17 – Wind Production Tax Credit by Year

Commence Construction (Prior to)	Production Tax Credit (%)
2017	100%
2018	80%
2019	60%
2020	40%

5.2.5.2 Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into solar photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

Photovoltaic (PV) cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. See Figure 5.17 for further details on the solar PV technologies evaluated.

Figure 5.18 – Solar Photovoltaic

Operating Characteristics and Estimated Costs	3 MW Solar PV	6 MW Solar PV	9 MW Solar PV	50 MW Solar PV	100 MW Solar PV
Base Load Net Output (MW)	3	6	9	50	100
Base Project Costs (2015$/kW)	$3,420	$2,700	$2,540	$2,260	$2,230
Fixed O&M Costs (2015$/kW-year)	$19.50	$19.50	$19.50	$19.50	$19.50

As discussed in Section 1.3.8, Solar Generation, the Investment Tax Credit (ITC) is a federal tax credit as a percent of basis invested in eligible properly. Investment tax credit percentage depends on the commencement of construction as shown below in Figure 5.19. For modeling purposes, Vectren assumed commercial operation date and commence construction to be the same year for solar projects. The eligible investment was assumed to be the total invested project costs to build. The Investment Tax Credit was normalized over the book life of the asset, which evenly distributes the tax credit out over the asset book life.

Figure 5.19 – Solar Investment Tax Credit by Year

Commence Construction (Prior to)	Investment Tax Credit (%)
2017	30%
2018	30%
2019	30%
2020	30%
2021	26%
2022	22%
1/1/2022 & beyond	10%

5.2.5.3 Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels, and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 5.20 for further details on the hydroelectric technology evaluated.

Figure 5.20 – Hydroelectric

Operating Characteristics and Estimated Costs	50 MW Low-head Hydroelectric
Base Load Net Output (MW)	50
Base Project Costs (2015$/kW)	$3,760
Fixed O&M Costs (2015$/kW-year)	$75.00

5.2.5.4 Waste-to-Energy

Two waste-to-energy (WTE) technologies were included within the analysis. Stoker boiler technology, or biomass, is the most commonly used WTE technology. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator for the production of electricity. The two fuel types evaluated in the IRP were wood and landfill gas, which are represented in Figure 5.21.

Figure 5.21 – Waste to Energy Technologies

Operating Characteristics and Estimated Costs	Wood Stoker Fired	Landfill Gas IC Engine
Base Load Net Output (MW)	50	5
Base Load Net Heat Rate (HHV Btu/kWh)	13,500	10,500
Base Project Costs (2015$/kW)	$4,720	$4,250
Fixed O&M Costs (2015$/kW-year)	$93.00	$180.00

5.2.5.5 Renewable Cost Curve Discussion

5.2.5.5.1 Solar

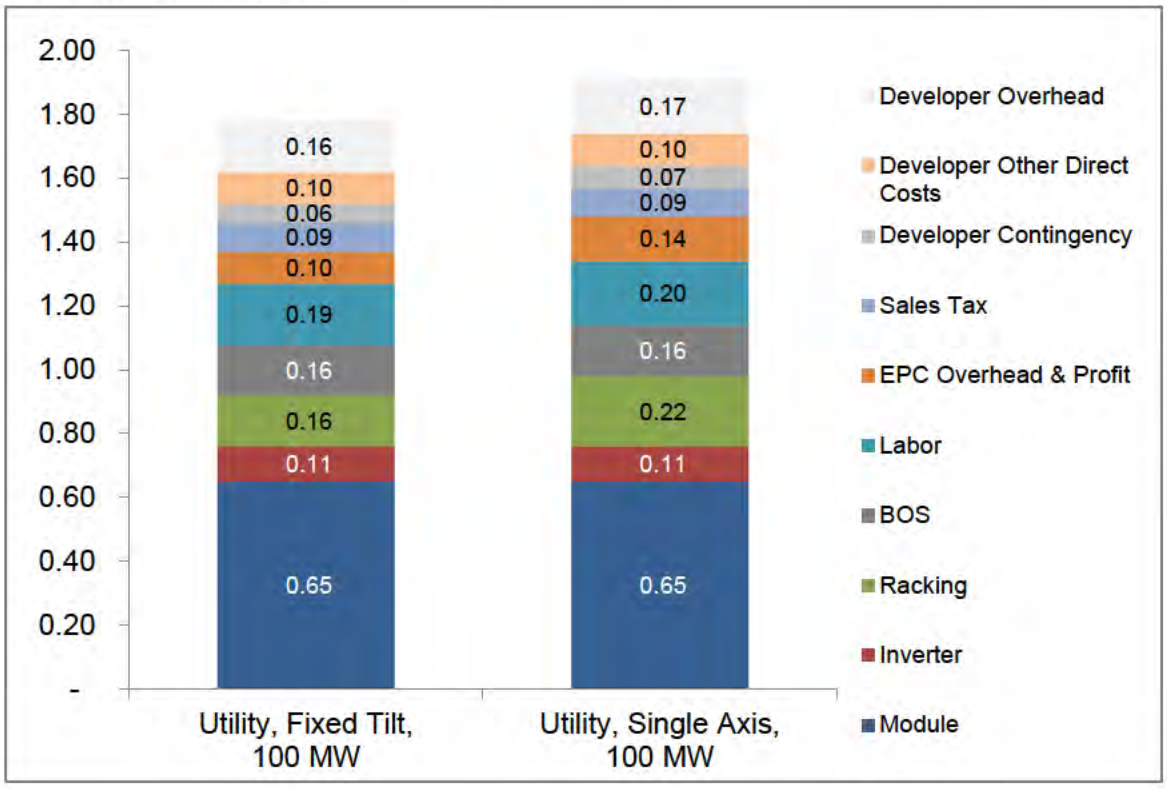
Current overnight capital cost estimates for solar technology were developed by Burns & McDonnell as part of the technology assessment. Pace Global then developed a long-term view of solar capital costs by reviewing public reputable studies and other IRPs. As

a result, Pace Global's estimates are derived from several quality references supplemented with analysis and expert judgment.

In the case of solar photovoltaics (PV), the National Renewable Energy Lab (NREL) provides a rich data set from which to explain current costs and trends. According to NREL, universal solar PV pricing has continued to decline over the last several years. While costs have declined in the past three years, the rate of decline has slowed significantly in the past two to three years as production scale and global competition has driven equipment pricing down[29]. Though some continued improvement in equipment cost is expected, NREL and other experts now expect most cost reductions will come from solar PV project soft costs. Soft costs generally include cost items such as Installation Labor, EPC Overhead & Profit, Developer Contingency, Developer Other Direct Costs, and Developer Overhead. For fixed tilt and single axis systems, soft costs comprise $0.60/Wdc and $0.68/Wdc (dollars per watt direct current), respectively.

[29] Sunshot report - Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections 2015 Edition", DOE Sunshot, Aug 2015, page 19, https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf

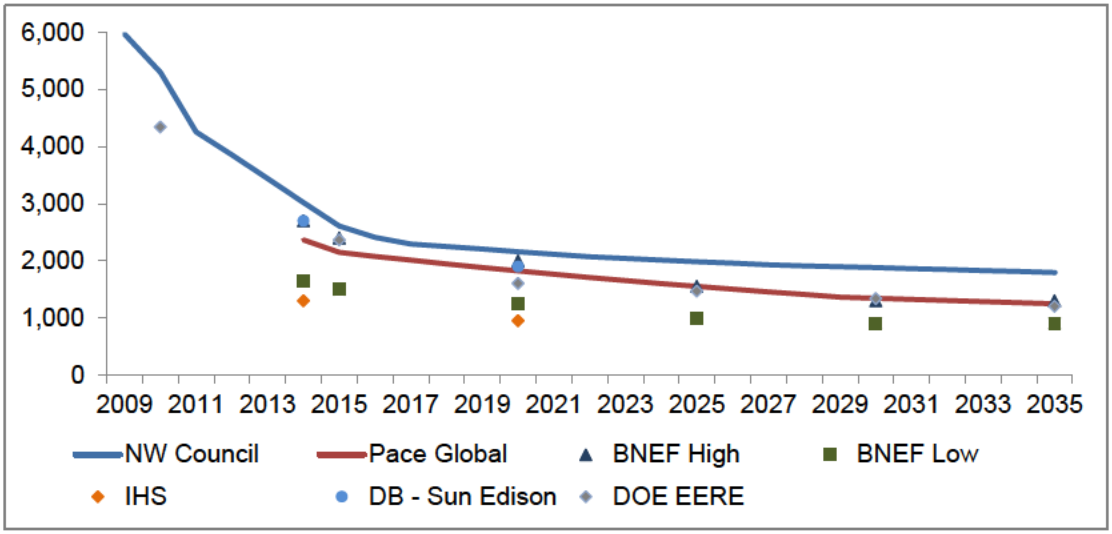
Figure 5.22 – Q1 2015 Universal Solar PV Cost Breakdown, 100 MW U.S. National Average, 2015$/Wdc[30]



To forecast capital cost for solar power generation technology, Pace Global reviewed numerous public sources regarding industry issues, trends, and predictions. Equipment, material, labor, and developer costs were considered to project the rate of cost change. This estimate was then compared with independent forecasts to ensure consistency. Pace Global expects solar capital costs to decline at a compound annual growth rate of 2.7% per year through 2036, which is in-line with other expert forecasts presented in the graph below.

[30] U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems; NREL, September 2015

Figure 5.23 – U.S. National Average Overnight Solar PV Capital Costs, 2015$/kW[31]



By combining the 2015 Indiana capital cost estimate with the anticipated decline rate in solar power generation technology costs, a specific forecast for solar PV costs in Indiana is derived.

5.2.5.5.2 Wind

Onshore wind-powered electrical generating technologies are becoming a mature technology. While wind project capital costs are expected to continue declining for several years as wind turbine pricing declines, the rate of decline is expected to slow.

Turbine nameplate capacity, hub height, and rotor diameter have all increased significantly over the long term. Though trends in the average nameplate capacity, hub height, and rotor diameter of turbines have been notable, the growth in the swept area of the rotor has been particularly rapid. All else being equal, increased swept rotor area results in greater energy capture for each watt of rated turbine capacity, meaning that

[31] The sources used to develop the above forecast are as follows: Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections 2015 Edition, DOE Sunshot, Aug 2015; U.S. Solar Market Insight Report, GTM Research and SEIA; Annual Technology Baseline and Standard Scenarios, NREL, July 2015; NW Council 2015 IRP; H1 2015 North American PV Outlook, Bloomberg New Energy Finance 01/16/15; Deutsche Bank, 02/19/15, 02/25/15, 05/04/15, 05/13/15; Solar Market Intelligence, IHS, 07/07/15; WindVision: A New Era for Wind Power in the United States, DOE EERE, Mar 2015; Pace Global client confidential data.

the generator is likely to run closer to or at its rated capacity and more often. The expected growth in capacity factors resulting from improved turbine designs is being held back by curtailments and inter-year wind resource variability. The strength of the wind resource varies from year to year, partly in response to significant persistent weather patterns such as El Niño/La Niña. A relatively strong El Niño in 2015 led to lower than expected wind speeds in the first two quarters, which reduced turbine output.

Based on these trends and observations, Pace Global estimates that 2016 overnight capital costs for an Indiana-based 50 MW wind farm are expected to decline by an average of one percent per year through 2030, with a lower decline rate of 0.3% per year thereafter.[32]

5.2.5.6 Out-of-State Wind

5.2.5.6.1 Contracted Wind Prices

Recent energy trade publications have touted the cheap energy production costs and increased capacity factors (the average power generated, in relation to the rated peak output of the wind turbine) of wind rich areas located in various parts of the MISO footprint, all of which are outside of Indiana. Combined with certain geographic locations being greater in wind output, technological innovation, production tax incentives, and various other factors, the contracted price of wind energy has decreased over time. Based on data from the U.S. Department of Energy, wind output in the plains states of Iowa, Oklahoma, and Kansas yields more megawatt hours and therefore a lower cost per MWh than Indiana wind resources[33]. The differences in cost per MWh are as much

[32] Pace Global used the following sources in developing this capital cost decline curve: 2015 Wind Technologies Market Report, August 2015, EERE; EIA AEO 2016 Assumptions; Lazard Levelized Cost of Generation Study, version 9.0, NOV 17 2015; The Cost Landscape of Solar and Wind, America's Insight, Jan 2015, BNEF; WindVision: A New Era for Wind Power in the United States, DOE EERE, Mar 2015; RE Map 2030, IRENA, May 2015; Most recent IRPs from Entergy Arkansas, NW Power Council, TVA, and Pacificorp.

[33] U.S. Department of Energy, National Renewable Energy Laboratory http://www.c2es.org/technology/factsheet/wind

as $20 and place wind energy from the plains states at prices competitive with conventional electric power generation.

Growth of wind resources moderated in 2015 due in part to the uncertainty regarding the renewal of the federal tax credits. However, in December Congress extended the investment and production tax credits of $23/MWh and allowed for wind resources under construction by 2016 to receive the full credit for the first 10 years of operation. The credit decreases 20 percent per year for units that begin construction each year from 2017 through 2019. Additional wind growth may also occur in the coming years as Multi Value [Transmission] Projects ("MVP") are completed, which include 17 transmission projects with regional benefits expected to significantly exceed the estimated $6.3 billion cost[34].

5.2.5.6.2 Total Cost of Delivered Wind

Aware of this generation shift and growth in wind generation, Vectren has monitored these developments and researched the current total cost of delivered wind. The total cost of delivered wind, as with any generation, that is accredited towards Vectren's planning reserve margin is comprised of three main factors: the cost of energy (the wind itself), the cost of delivering the energy (through transmission lines), and any transmission congestion charges (charges that are added to the energy component as a result of overloads on the system). In addition to cost consideration, other factors include timing, certainty, and access.

5.2.5.6.3 Delivering the Wind

Vectren has three options for delivered wind to serve load: 1) build a transmission line, 2) pay for use of existing MISO transmission through tariff rates, or 3) contract for

[34] 2015 State of the Market Report for the MISO Electricity Markets, By Potomac Economics, June 2016 https://www.misoenergy.org/Library/Repository/Report/IMM/2015%20State%20of%20the%20Market%20Report.pdf

subscriber-based transmission projects that charge a per MW rate for capacity (usage) of the line.

Building a specific transmission line for the sole purpose of delivering wind to Vectren load is an option that presents several challenges. The most obvious hurdle is cost. The cost of building high-voltage (138 kV and above) transmission to transport wind from the turbine to its desired load ranges from $1 million to $3 million per mile. For reference, MISO's most recent Market Efficiency [Transmission] Project "Duff to Coleman" is a 345 kV single circuit line that MISO has estimated to cost approximately $2,104,209 per mile[35]. Wind that would be accredited to Vectren load would have to be connected from the turbine to a MISO load zone. Wind located within Iowa, for example, would require less mileage to connect since Iowa is located within MISO, while wind in Kansas would require considerable spans of transmission to connect to MISO. In addition to the cost of connecting wind into MISO via constructing a new line, there is the coordination and increased requirements dictated by the system in which the wind generator is physically located. This would include additional study costs and possible upgrades to that system's transmission facilities. Building a transmission line to deliver wind would only be viable if the wind is located within or near a MISO load zone.

Part of the benefit of being a member of MISO is the open access it provides to MISO transmission and the avoidance of pancaking, paying a separate rate to each transmission owner to pass energy through its line, of transmission rates. Wind that is connected to existing MISO transmission would pay defined tariff rates for usage of the path. These tariff rates vary for each Load Serving Entity (LSE), but in most instances for Vectren, add $1-$5 of cost per MWh. However, before a generator can tie-in to the MISO system, a System Impact Study (SIS) must be performed that will analyze the impact that generator will have on the entire system and identify any transmission

[35] MISO 2015 MEP Bid Summary
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2015/20150729/20150729%20PAC%20Item%2004%20Duff%20Coleman%20Project%20Estimate.pdf

upgrades needed as result of the additional generation onto the system. This cost is borne solely by the generator. The timing for the study results is approximately 12-18 months, and the cost is between $60,000 and $600,000 depending on the size of the unit.

The final option is subscribing to a transmission project and paying for transmission "capacity", or defined usage of the line, to deliver wind. The predominant subscriber-based developer of transmission lines in North America is Clean Line Energy, which currently has three proposed transmission projects that would bring wind from the west into the Midwest region. One of those projects, Grain Belt Express, would bring upwards of 3,500 MWs of wind into Sullivan, IN. This project would source wind energy from southwest Kansas, which has some of the highest capacity factor (the average power generated, in relation to the rated peak output of the wind turbine) wind in North America. All three of the projects are dependent upon a sufficient amount of subscribers to economically justify the construction of the lines and the regulatory approval process for the lines to traverse multi-state regions.

The Grain Belt Express transmission project has been delayed while Clean Line Energy Partners, the developer of the project, seeks regulatory approval from the Missouri Public Service Commission (MPSC). The MPSC has been the lone state to deny the approval of the project. Clean Line filed its third application with the MPSC on September 5, 2016. Representatives of the Block Grain Belt Express, the grass-roots organization that led to the project's rejection last summer, remain in opposition of the project as it cites health concerns and reductions in financial benefit as the main deterrents. The construction and right-of-way acquisition timeline could take 5-7 years if the MPSC approves the project.

5.2.5.6.4 Congestion Charges

Transmission congestion charges are the final element for consideration when analyzing the true cost of delivered wind and are the most difficult to estimate.

Congestion charges are calculated by taking the difference in Locational Marginal Pricing (LMP's) where the energy is injected (source) and where the energy is withdrawn (sink). For Vectren to purchase wind outside of Zone 6 (Indiana), Vectren would be responsible to pay the LMP at the sink and would receive payment from the source. Therefore, any price differential is an added risk and possible added cost to the delivery of wind. MISO does not provide estimates of congestion charges due to the volatility and immense variability that impacts the MISO transmission system and the congestion related charges. When considering the cost of wind, the required transmission charges, and estimated congestion charges based on historical data, the greater the distance, the greater the potential for higher costs.

5.2.5.6.5 Analysis

MISO's current transmission system is not designed to support a large influx of variable resources, such as wind, and is undergoing a paradigm shift that involves further build-out of its system to accommodate the unique properties of wind. Currently during periods of high wind, MISO has to curtail individual wind units due to overloading of the MISO transmission system.

While wind resources account for less than 10% of both energy and capacity within MISO, they still set negative LMPs in the local areas they are located in almost half of the time. A negative LMP means that MISO must be paid for each MWh put on the grid. Typically MISO pays producers to put power on the MISO grid. Negative LMPs are intended to signal generators that their power is not needed. This is due to the frequent curtailment of wind generation to manage congestion. As wind continues to increase its makeup of MISO capacity, additional transmission build-out may be needed to deliver the wind from wind rich areas to large load bases[36].

[36] MISO's Analysis of EPA's Final Clean Power Plan Study – June 2016 page 6
https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2016/20160615/20160615%20PAC%20Item%2002a%20MISO's%20Analysis%20of%20EPA's%20Final%20Clean%20Power%20Plan%20Study%20Report%20Draft%202_Highlighted%20Changes.pdf

Additionally, although wind is more than 9% of MISO's installed capacity (ICAP), it is less than 2% of MISO's unforced capacity (UCAP), which means that for planning purposes, its capacity credit is approximately 15% of its stated generation capability and can only be relied upon for that amount. For the 2016-2017 planning year, MISO's system-wide wind capacity credit is 15.6%[37]. Wind located in MISO's Zone 1 (Montana, North Dakota, South Dakota, Wisconsin, and Michigan) receives a UCAP value, or Effective Load Carrying Capability (ELCC) of 18.8% of installed capacity, while wind in Zone 6 (Indiana and Kentucky) receives virtually half that amount at an estimated 9.6%. Essentially, utilities in Zone 6 only get to approximately 10 MW out of every 100 MW, depending on location and performance, to meet the MISO's planning reserve margin requirement. This calculation is based mainly on historical output of each wind resource, while also considering the wind resource's location. Given the uncertainty around out-of-state wind costs, Vectren utilized an estimate of in-state wind for this analysis. As projections of out-of-state wind costs become more certain, Vectren will re-evaluate out-of-state wind in future IRPs.

5.2.6 Energy Storage

Two energy storage technologies were evaluated in the IRP –batteries and compressed air energy storage (CAES). These are shown in Figure 5.24.

Batteries utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging, and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity.

To utilize CAES, a suitable storage site is needed, either above or below ground, as well as availability of transmission and fuel source. CAES facilities use electricity to

[37] MISO's Planning Year 2016-2017 Wind Capacity Credit Report – December 2015
https://www.misoenergy.org/Library/Repository/Report/2016%20Wind%20Capacity%20Report.pdf

power a compressor train that compresses air into an underground reservoir at approximately 850 pounds per square inch (psig). Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander. The expander is essentially a turbine that spins as the compressed air is released from storage.

Both battery and CAES technology offer a way of storing low-priced, off-peak generation that can be discharged during higher-priced, peak demand hours.

Figure 5.24 – Energy Storage Technologies

Operating Characteristics and Estimated Costs	Lithium Ion 10 MW / 40 MWh	Lithium Ion 1 MW / 1 MWh	Commercial 100 kW / 250 kWh	Residential 2 kW / 7 kWh	CAES
Base Load Net Output (MW)	10	1	0.1	0.002	100
Round-Trip Cycle Efficiency	90%	90%	90%	90%	75%
Base Project Costs (2015$/kW)	$3,050	$2,430	$3,080	$3,480	$1,490
Fixed O&M Costs (2015$/kW-year)	$16.20	$40.80	$50.40	$60.00	$7.00

5.2.6.1 Energy Storage Cost Curve Discussion

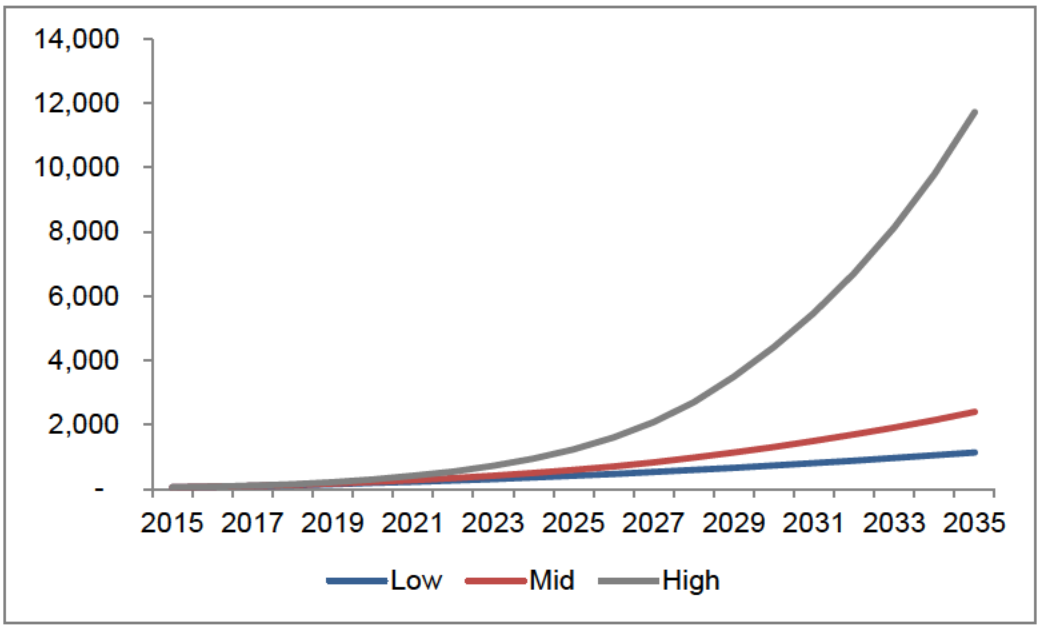
Current overnight capital cost estimates for battery technologies (residential, commercial, and universal) were developed by Burns & McDonnell as part of the technology assessment. Pace Global then developed a long-term view of battery capital costs by class from the expected volumetric growth in lithium-ion battery sales for automotive and grid support applications and anticipated technology learning rates. Data supporting this analysis was sourced from public independent expert studies and available IRPs. The approach is tried and tested, frequently applied during the early stages of new technology adoption to estimate demand and pricing when measured market data is limited.

A single deterministic price forecast may introduce bias that skews the forecast path. To counter this, Pace Global sought to develop a reasonable range of price expectations to support the stochastic market analysis. The selected approach is founded on the principle that as greater numbers of similar sizes and types of batteries are manufactured, economies of scale and learning effects from manufacturing engineers will result in reduced unit production costs. Such a belief is well-supported in literature.

Pace Global developed a forecasted range of lithium-ion battery sales for similar applications, specifically automotive and grid support, but not consumer electronics. A June 2015 report to the National Renewable Energy Lab (NREL)[38] provided a forecast of demand for lithium-ion batteries used in several applications, as well as forecast growth rates from several leading experts[39] ranging from 22% to 41% through 2020. By combining these outlooks, several lithium-ion battery sales forecasts were derived for the period 2016-2036.

[38] Automotive Lithium-ion Battery (LIB) Supply Chain and U.S. Competitiveness Considerations, Clean Energy Manufacturing Analysis Center, June 2015
[39] Roland Berger, Navigant Consulting, AAB, Avicenne, and CEMAC

Figure 5.25 – Global Lithium-Ion Battery Sales Forecast, Automotive & Grid Applications, 2015-2036 GWh



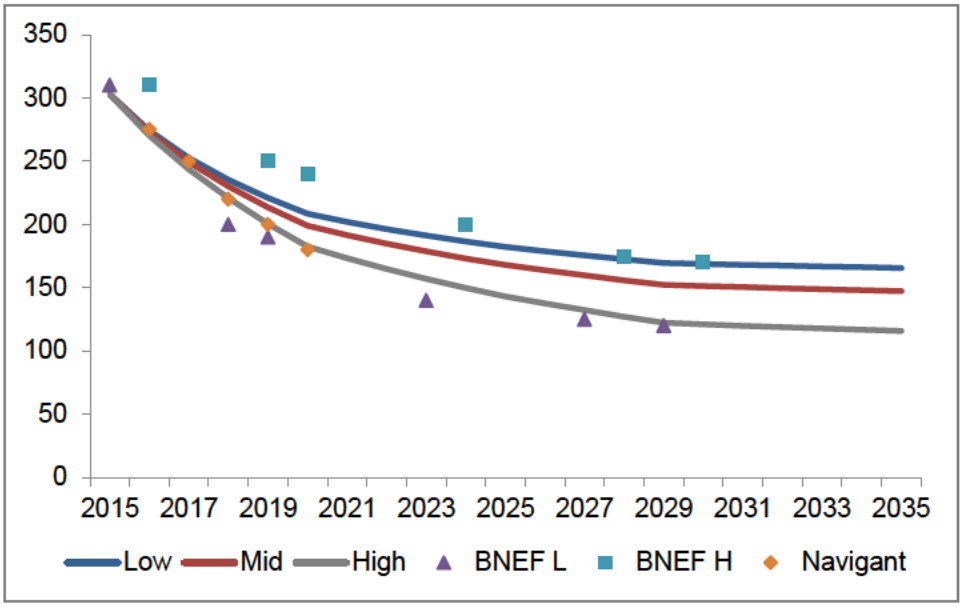
Pace Global then researched publically available literature to determine recently reported progress and learning rates for lithium-ion battery development and other power generation technologies. A nonlinear learning function and a progress ratio formula are developed to estimate the speed of learning (i.e. how much costs decline for every doubling of capacity). To apply this approach, three large format lithium-ion battery sales growth and learning development scenarios were developed with growth rates applied in each of four stages of market development. This resulted in three unique sales forecasts to which the aforementioned learning model was applied. Four different learning rates were developed to align with the four stages of market and technology development. When applied, three independent lithium-ion battery price paths were estimated based on market growth and learning expectations. The results of these derivations were compared with other publically available projections[40,41] to

[40] Bloomberg New Energy Finance Summit 2015, April 2015

41 The Lithium Ion Battery Market, Navigant, Jan 2014

assess the reasonableness of the results. The results and comparison against other available sources are presented in the graph below[42].

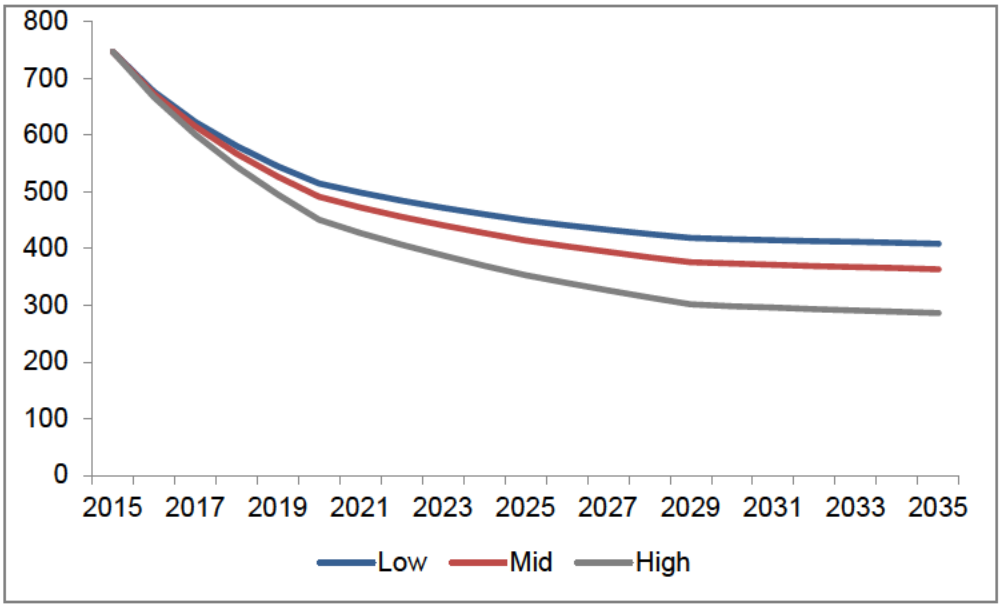
Figure 5.26 – Lithium-Ion Battery Storage Cost, $kWh



A lithium-ion battery-based bulk energy storage system requires more than batteries to deliver energy to the grid on demand. To estimate the overnight cost of the battery storage system, Pace Global estimated the additional balance of plant costs that a utility would require to complete the system. To finalize the all-in cost estimate, a financing charge (IDC/AFUDC) appropriate to the expected loan was added. The all-in utility scale lithium-ion battery storage cost estimates for the different market growth and learning expectations are displayed in the graph below.

[42] The sources used to develop the above forecast are as follows: The Cost Landscape of Solar and Wind, America's Insight, Jan 2015, BNEF; Bloomberg New Energy Finance Summit 2015, New York, April 2015; Energy Storage, EV's and the Grid, Tesla Motors, 2015 EIA Conference, June 15, 2015; Batteries Charge Up For the Electric Grid, Moody's, 24 SEPTEMBER 2015; The Economics of Load Defection, Rocky Mountain Institute, April 2015; U.S. Electric Utilities & IPPs, Storage Deep Dive Highlights Supply Chain Risks, 18 September 2015; Batteries and Energy Storage, NY Battery and Energy Storage, June 2015; Lazard's Levelized Cost of Storage Analysis – Version 1.0, November 2015; U.S. Energy Storage Monitor, Q1 2015, May 2015, GTM Research; Pace Global proprietary Li-ion production cost model; Pace Global client confidential data.

Figure 5.27 – All-In Utility Scale Lithium-Ion Battery Storage Cost, $/kWh



5.3 MISO CAPACITY CREDIT

Each resource option receives varying amounts of capacity credit within MISO based on their ability to reliably contribute capacity at the peak demand hour. Combined cycle gas turbines are considered base load (24/7 power) and can produce an expected level of output when called upon. For this reason, utilities are able to count nearly the full installed capacity for CCGTs (less their historical outage rate). A new combined cycle facility can count 96 MWs out of every 100 MWs of installed capacity towards meeting the MISO's planning reserve margin requirement. Renewable wind and solar resources are variable sources of power (available when the wind blows or the sun shines), which means they are not always available to meet peak demand. Neither wind nor solar resources tend to reliably provide their full installed capacity at the peak demand hour, as such, they receive less capacity credit.

Typically, renewable wind resources do not produce much energy during hot summer days when Vectren normally sees peak demand. Vectren's receives approximately 11% capacity credit towards meeting planning reserve margin for its wind resources.

While renewable wind resources produce a lot of renewable energy, they cannot be counted on for capacity. A solar power plant in Southern Indiana is expected to receive 38% capacity credit. For every 100 MW of installed capacity, Vectren would receive 38 MWs of capacity credit from MISO. The tradeoff between renewable wind and solar resources is energy need vs capacity need. Within optimization modeling, solar tends to be selected as a resource before wind when there is a capacity need.

Figure 5.28 – MISO Capacity Credit

Accredited Capacity	CCGT	GT	Wind[43]	Solar[44]
% of Summer output	96%	76-94%	11%	38%

5.4 TRANSMISSION CONSIDERATIONS

5.4.1 Description of Existing Transmission System

Vectren's transmission system is comprised of 64 miles of 345 kV lines, 374 miles of 138 kV lines and 565 miles of 69 kV lines. It has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (138 kV), and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy's system in the area of Duke's Gibson Generation Station, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at IPL's Petersburg Generation Station, and 138 kV interconnections to Hoosier Energy, LGE/KU, and Big Rivers at Vectren's Newtonville Substation.

[43] For wind, 11.25% (based on actual performance of Benton County and Fowler Ridge units) was used to calculate the amount of UCAP available for modeling.
[44] For solar PV, 38% was used to calculate the amount of UCAP available. This number closely aligns with the PJM capacity credit for solar and NREL expectations for the Vectren service territory.

5.4.2 Discussion on Resources Outside of Area

As mentioned above, Vectren's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 900 MWs (or approximately 75% of peak demand). Although Vectren has the capability to offset internal generation with imported capacity, this is not a long term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)

5.4.3 Evaluation of Various Resource Configurations as an Input to the Optimization Model

Vectren performed an analysis of its transmission system's performance in an effort to understand the high-level impact of building a combined cycle gas turbine plant to replace the existing AB Brown 1 and 2 coal units. Transmission enhancement cost estimates were developed for this scenario and used as an input to the optimization model.

The following outlines the basic assumptions used in this analysis:

Figure 5.29 – Transmission Input Analysis Assumptions

Generator Retirements:	Vectren Generators Available:
Culley Unit 2 – 90 MW	AB Brown Unit 3 – 80 MW
BAGS Unit 1 – 60 MW	AB Brown Unit 4 – 70 MW
Northeast Units 1 and 2 – 20 MW	BAGS Unit 2 – 60 MW
Warrick Unit 4 - 300 MW[45]	New AB Brown CC ST – 422 MW
	New AB Brown CC CT – 211 MW
	New AB Brown CC CT – 211 MW
	Culley 3 – 270 MW
Generator Modeling Notes: Coal unit retirements occur at the end of 2023. On January 1, 2024, a new 844 MW[46] A.B. Brown combined cycle adds two new 211 MW combustion turbines and a 422 MW steam turbine (output based on summer temperature of 90F).	

In this scenario, west to east power transfer becomes an issue due to the increased output of the AB Brown plant. This problem would be magnified should ALCOA-Warrick generating facility (units 1-4) shut down. Additionally, voltage performs poorly on the east side of the transmission system due to the loss of reactive power support from the Warrick power plant.

Several projects were modeled to mitigate the west to east power transfer issue. A new 138 kV line from the AB Brown power plant to Pigeon Creek substation to the Culley power plant along with miscellaneous 69 kV upgrades mitigated all of the issues. In order to provide sufficient reactive support, a synchronous condenser was modeled. The estimated cost for these projects is listed below.

[45] There is still uncertainty with respect to the ALCOA-Warrick generation facility following the retirement of ALCOA's aluminum smelter. A conservative planning approach was taken in this analysis and all four Warrick generating units were modeled as retired with Vectren serving the remaining ALCOA load.
[46] 889 MW is expected output at 59 degrees (average annual temperature)

Figure 5.30 – Estimated Cost of Transmission Modeling Input

New 138 kV Line	$31,840,000[47]
138 kV Terminal Upgrades	$1,150,000
138 kV Terminal Relocation	$250,000
Misc. 69 kV Upgrades	$2,179,500
Synchronous Condenser Conversion	$6,000,000
Total	**$41,419,500**

Cost Estimate Notes:

- The cost for the 138 kV line was based on 12 miles through suburban terrain ($800k per mile), followed by 12 miles double circuited with a 69 kV line through Evansville metro ($1,000k per mile), and then followed by 12.8 miles through suburban terrain ($800k per mile). The distances are based on a preliminary route developed by Vectren transmission engineering.
- The 138 kV terminals were based on estimates of $150k per breaker (one installed at AB Brown, two at Pigeon Creek, and two at Culley) plus $100k per dead-end terminal (four total). These costs are based on actual costs from several recent projects.
- The $250k for the terminal relocation is for AB Brown. There is an open bay for a new 138 kV terminal; however, it shares a common breaker with Z93 AB Brown – Northwest. A fault on this breaker outages both the new line and Z93, causing an overload on Z99 AB Brown – Northwest. Z93, Z99, and the new line need to be on different rungs to prevent a breaker fault overloads. The cost for this was based on a recent project to relocate 138 kV line terminals at another substation, escalated due to the more complex nature of this relocation. Also, this cost is a high-level budget number because the design for this relocation has the potential to be very complex and there are currently too many unknowns.
- The 69 kV upgrades include 1.83 miles of conductor upgrade through Evansville metro ($650k per mile), 12 switches to be replaced ($37k each), and 0.21 miles of underground conductor to be replaced ($2,600k per mile).

[47] Vectren engaged a third-party consultant to verify the cost estimate for the new 138 kV line. The third-party estimate was approximately $37M, or $6M higher than the original cost estimate.

- A synchronous condenser was modeled to provide reactive support, with a cost provided by GE. However, it is possible that an SVC or STATCOM device would also provide sufficient support. These devices could be studied more in depth if this scenario moves forward.

5.5 BUSBAR SCREENING

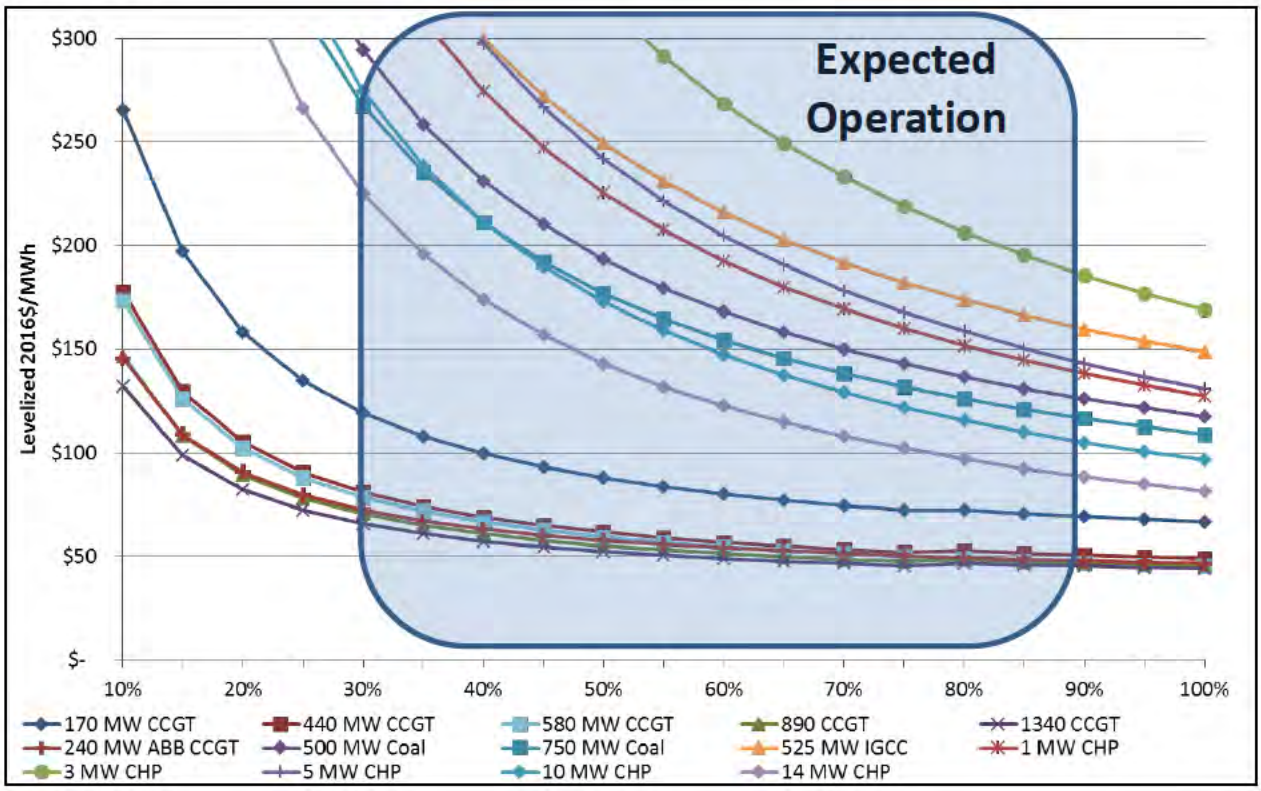
Vectren considered a wide variety of power supply alternatives including 24/7 baseload, intermediate, and peaking options, as well as renewable generation, energy storage, distributed generation, and demand side management. These power supply alternatives were screened using a busbar levelized cost of electricity analysis. Levelized cost of electricity is the net present value of costs to install and operate an energy system divided by its expected energy output over a defined time period. The busbar analysis was done in order to reduce the number of alternatives that would be simultaneously evaluated within Strategist, the planning model.

The screening analysis was performed by developing and comparing the levelized cost of electricity for each resource over the same 20 year period. This simple approach is used to identify and limit the number of higher-cost generation alternatives that would otherwise be expected to operate in a similar nature to lower-cost alternatives. For screening purposes, estimated costs included emissions (CO_2), fuel, operation & maintenance, and capital costs. Resources were then compared across various capacity factors in order to compare resource costs across all dispatch levels. Variable resources were compared at their respective output levels.

Using the calculated busbar levelized cost of electricity analysis, technology alternatives were screened for Strategist optimization modeling based on: cost effectiveness, feasibility, and capacity size. The alternatives screened using the busbar levelized cost of electricity calculations are shown in Figure 5.31. Note that in the following Figures 5.31-5.32 the x axis is capacity factor and the y axis is Levelized 2016 $/MWh.

Demand side management (DSM) was not considered in the busbar analysis, but was included as one of the alternatives within the IRP modeling.

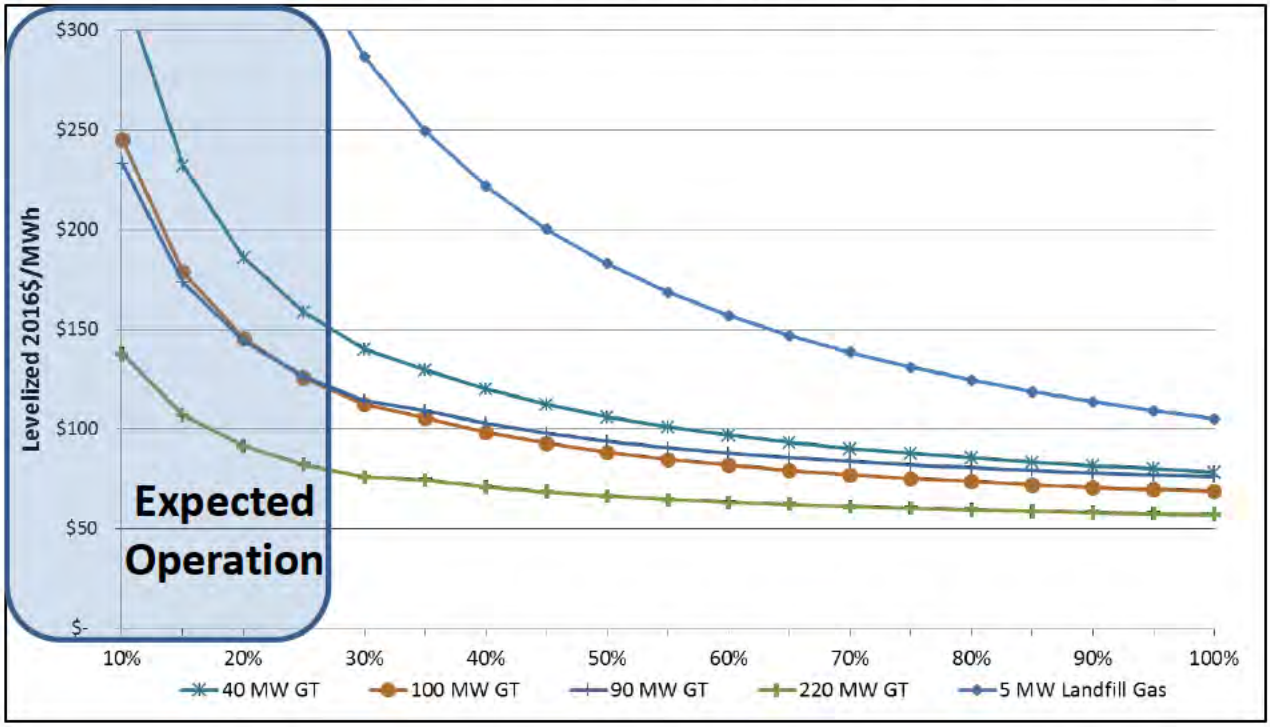
Figure 5.31 – 20-Year Levelized Cost of Electricity: Base and Intermediate Load Resources



The F-class combined cycle gas turbines show the lowest levelized busbar cost across all capacity factors. Due to 3x1 7FA.05 (1,340 MW) exceeding Vectren's forecasted planning reserve margin requirements, this alternative was eliminated from further analysis. Based on the screening results of the base and intermediate resources, the 1x1 7FA.05 (440 MW), 2x1 7FA.04 (750 MW), and 2x1 7FA.05 (890 MW) combined cycles were considered for further analysis within Strategist.

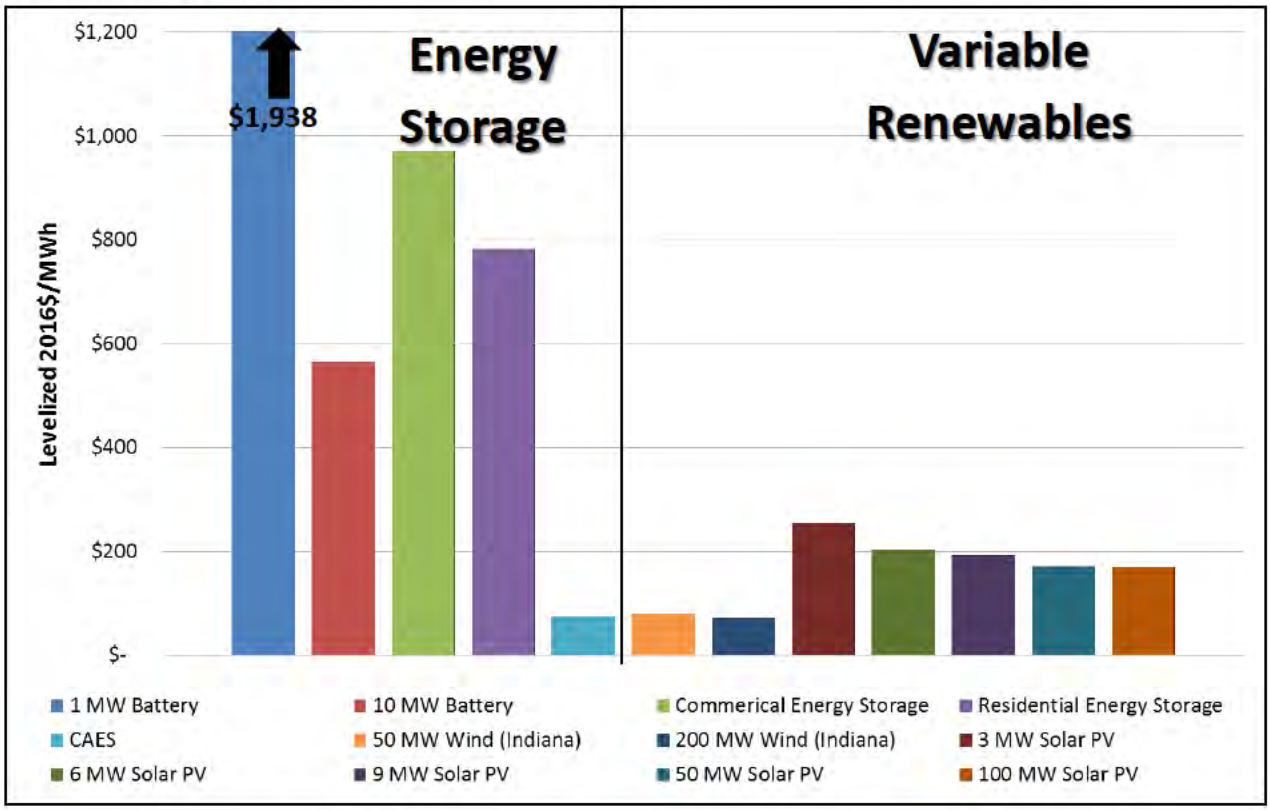
For combined heat and power, the 14 MW option was the lowest cost option evaluated. The 14 MW CHP was included in the Strategist modeling due to the size flexibility and being the most economical CHP option considered.

Figure 5.32 – 20-Year Levelized Cost of Electricity: Peaking Load Resources



The F-class simple cycle gas turbines show the lowest levelized busbar cost across all capacity factors. Due to the smaller project size available with the LMS100 (100 MW), this presented a smaller simple cycle option. The F-Class SCGT (220 MW) and LMS100 (100 MW) technologies were considered for further analysis within Strategist.

Figure 5.33 – 20-Year Levelized Cost of Electricity: Energy Storage & Renewable Load Resources



Two types of renewable resources were included in the final integration analysis. The renewable resources were modeled in various size blocks to be evaluated against the other new construction alternative options. The renewable technologies that were selected by the busbar cost analysis included wind and solar photovoltaic (PV).

Compressed air energy storage was the lowest cost storage option, but was eliminated due to limited feasibility (likely not available) in Vectren's service territory. Suitable underground storage would need to be identified. The 10 MW/40 MWh Lithium Ion represented the next lowest cost storage. Based on the levelized cost of electricity results, the 10 MW/40 MWh battery was carried forward as an alternative in Strategist for the high tech scenario.

SECTION 6
SCENARIOS: OPTIMIZATION MODEL INPUTS & ASSUMPTIONS

6.1 BASE CASE

Vectren developed a base case forecast of key market drivers as inputs into this IRP process that collectively represent the expected path most likely to occur. For many of these assumptions, including natural gas prices, coal prices, and carbon prices, a wide range of views were incorporated into a consensus forecast. For load growth, Vectren developed a bottom-up, forward looking view that incorporates energy, customers, prices, economic drivers, appliance saturation and efficiency, long-term weather, customer owned generation, hourly system load, and 10-year average peak-day weather. The following sections detail these base case assumptions.

The base case scenario is a consensus forecast. Hence, it is impossible to describe specifics regarding the assumptions driving the forecast. However, the base case can be described in more general terms based upon consistency in general trends among the individual forecasts that comprise the consensus forecast. Generally, the forecast is characterized by reasonable and balanced levels of growth and drivers that lead to moderate market price increases over time. Power market participants under base case conditions are able to adapt and adjust in a timely manner to changing market forces.

Short Term: In the short-term (2016-2018), the base case generally assumes positive sales growth as the economy continues to improve and as Vectren adds new customers to its base. Residential customer growth remains positive, albeit lower, than pre-recession levels, but this is partially offset by moderately declining average use per customer. Similarly, the customer base for small and large commercial and industrial (C&I) customers continues to grow, but with a partial offset of this growth by increasing efficiency. As a result, energy sales grow at a moderate pace.

Natural gas prices remain low through 2016 and 2017 as the current oversupply situation continues to dominate gas market dynamics. However, low prices eventually result in restricted production and reduced gas supply. Coupled with new LNG export terminals and new heavy industrial facilities, demand rises and gas markets begin to

tighten. This is especially true in the premium Gulf Coast market, where much of the demand is materializing, pushing prices incrementally higher in 2018 and beyond. Gas prices in the Utica/Marcellus also recover in 2018 and 2019 as several pipeline projects that provide takeaway capacity enter into service.

Meanwhile, coal prices remain depressed in the near short-term as domestic markets remain soft, with a modest price recovery beginning in 2018.

Market power prices for residential and commercial customers historically have declined since the 2008 recession, but both are expected to experience slight upward price increases over the next few years, based on rising future operating costs and associated revenue requirements. Increased revenue requirements are due to rising replacement and retrofit costs imposed by EPA's ELG regulation as well as by declining reserve margins that compel new builds. Capital costs are generally expected to increase at a moderate pace, reflecting increased costs for labor as the unemployment rate remains at a relatively competitive five percent and higher borrowing costs from rising interest rates, but tempered by lower costs for material as commodity prices remain broadly lower.

Coal plant retirements were high in 2015 driven by regulation including MATS, but continue at a comparatively much more moderate pace in the next few years. Meanwhile, capacity additions in the form of efficient combined cycle gas turbine plants continues at a healthy pace as merchant plants and utilities continue to take advantage of actual and expected low gas prices.

Medium Term: In the medium-term (2019-2025), the base case consensus forecast reflects the assumption that most states, including Indiana, will opt for a mass-based Clean Power Plan (CPP) compliance approach due to the expected broader trading opportunities, albeit with a two year delay of the beginning of the compliance period (from 2022 to 2024) due to the legal uncertainty following the U.S. Supreme Court stay.

Mass-based is seen as a more optimal compliance approach for coal heavy states relative to the rate-based approach alternative. Specifically:

- It is considered simpler and easier to administer than a rate-based plan.
- Retirements of older inefficient plants that are occurring primarily due to economics.
- States will feel pressure to join together to create the most liquid market and largest possible pool of trading partners for emissions reductions.

In the medium-term, energy efficiency standards and energy company sponsored DSM programs mostly offset the growth in energy sales from a growing residential customer base. However, overall load growth continues to grow at a moderate pace, driven by new C&I customers locating in the Midwest to take advantage of access to low-cost shale gas.

Natural gas prices at the Henry Hub do increase to $4/MMBtu and above as markets tighten significantly on the Gulf Coast. Midwest gas prices continue to benefit from proximity to the Utica and Marcellus shale plays, helping to keep regional gas price growth to a more moderate level.

Coal prices recover most strongly in the Illinois Basin to 2020, with a modest recovery in the Powder River Basin and very limited recovery in the Appalachian region, due to consolidation among producers, lowered production that tightens supply, and a modest export market.

CO_2 prices in California and in Northeast states participating in RGGI harmonize with the broader U.S. market as the CPP compliance period begins in 2024. Given that the CPP allows for interim goals for compliance, CO_2 prices are expected to increase moderately as states adapt to the compliance regime and carbon markets have time to adjust.

Market power prices continue to move upward moderately as the CPP compliance period begins. Fuel costs increase incrementally with new export demand markets. As the customer base continues to grow, energy company operating costs continue to rise. Commodity markets recover in the medium-term, pushing up material costs and consequently capital costs. In addition, as the overall economy continues to make improvements and the unemployment rate remains around five percent, capital costs rise as competitive upward pressure remains on labor costs.

Coal-plant retirements mean no emissions from retired plants, which contribute to lowering total emissions under a mass-based approach. Through the years after the CPP goes into effect in 2024, coal plant retirements will continue to be driven by plant-specific going-forward economics. Meanwhile, capacity additions largely come from natural gas combined cycle turbines, solar, and wind facilities.

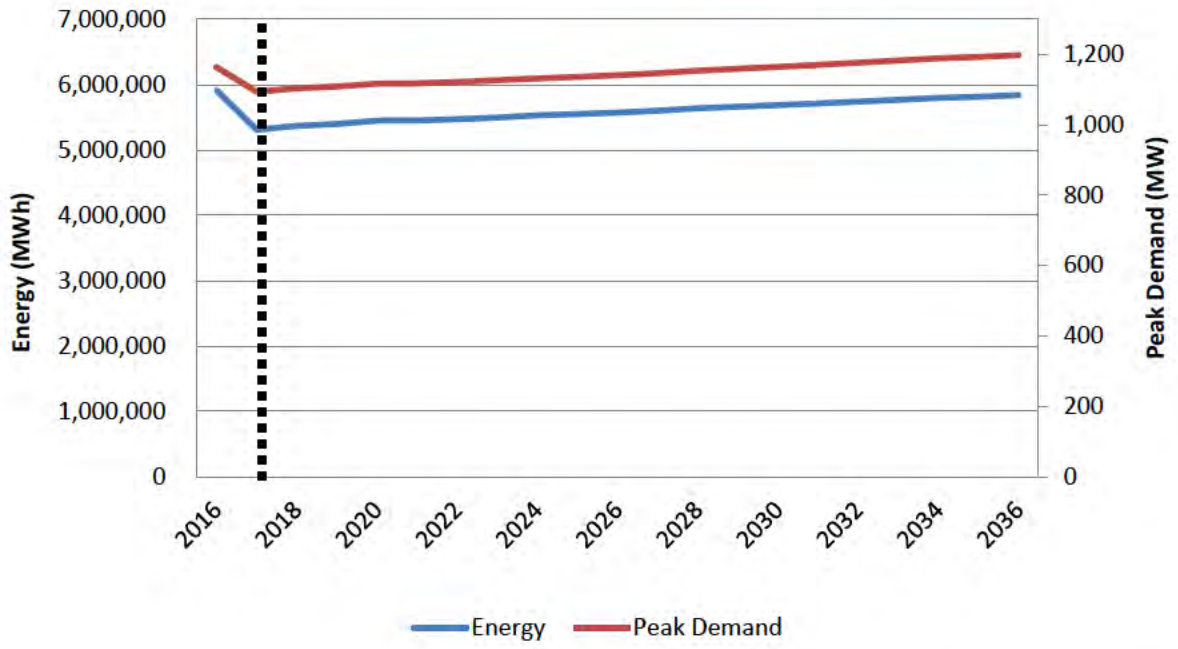
Long Term: In the long-term (2026-2036), the suite of market outcomes and drivers in the base case settles into a pattern of moderate growth based on a well-balanced market. Markets have sufficient time to adapt and adjust as the final CPP goal in 2030 nears and as regulation is expected to be extended to 2036 and beyond, helping keep CO_2 prices reasonable if growing. Energy demand grows as electric car sales take hold but is offset by continued gains in distributed generation and energy efficiency measures. Domestic shale gas and coal resources help to keep fuel cost growth to a moderate level. Capital costs increase at a measured pace as the GDP growth rate averages two percent or more. Capacity additions and retirements continue at a reasonable rate as the fleet of power plants maintains a healthy rate of turnover.

6.1.1 Input Forecasts

The long-term energy and demand forecast for the Vectren service territory was developed for Vectren by Itron. For more information, please see Section 4 Customer Energy Needs. The forecast is based on a combination of historical usage trends and a bottoms-up approach to drivers such as residential and commercial demand, industrial

load, appliance saturation, energy efficiency, long-term weather trends, customer-owned generation, and an outlook for economic factors.

Figure 6.1 – Base Case Vectren Load Forecast (MWh and MW)



For natural gas, coal, and carbon, Vectren used a "consensus" base case view of expected prices by averaging forecasts from several sources. For natural gas, forecasts from Ventyx, Wood Mackenzie, EVA, and PIRA were averaged. For carbon, forecasts from Pace Global, PIRA, and Wood Mackenzie were averaged. This helps to ensure that reliance on one forecast or forecaster does not occur.

Figure 6.2 – Base Case Natural Gas Price Forecast (2015$/MMBtu)

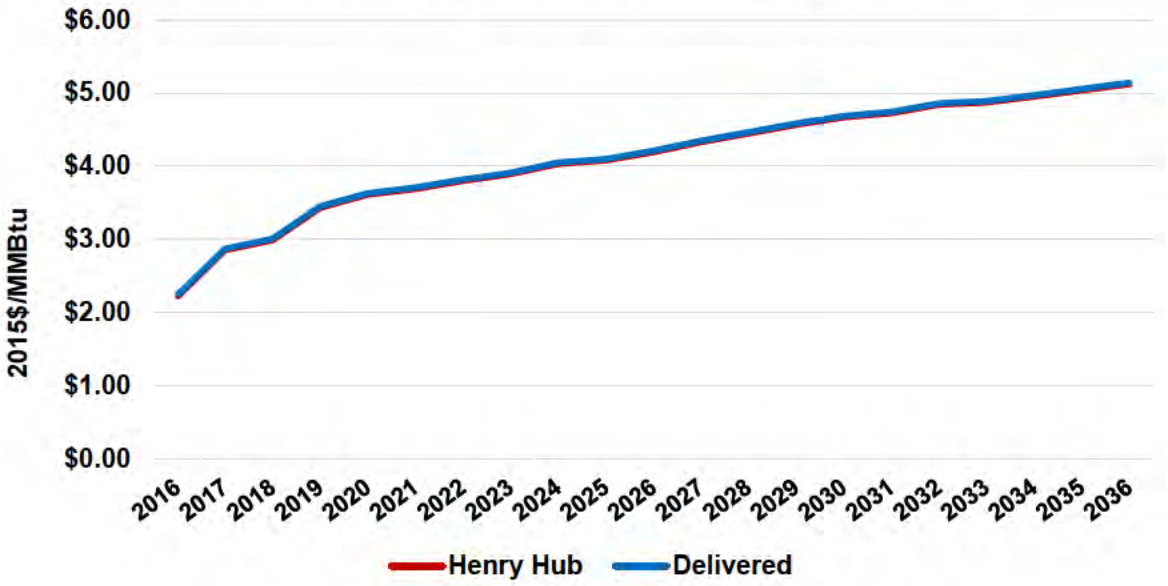


Figure 6.3 – Base Case Coal Price Forecast (2015$/MMBtu)

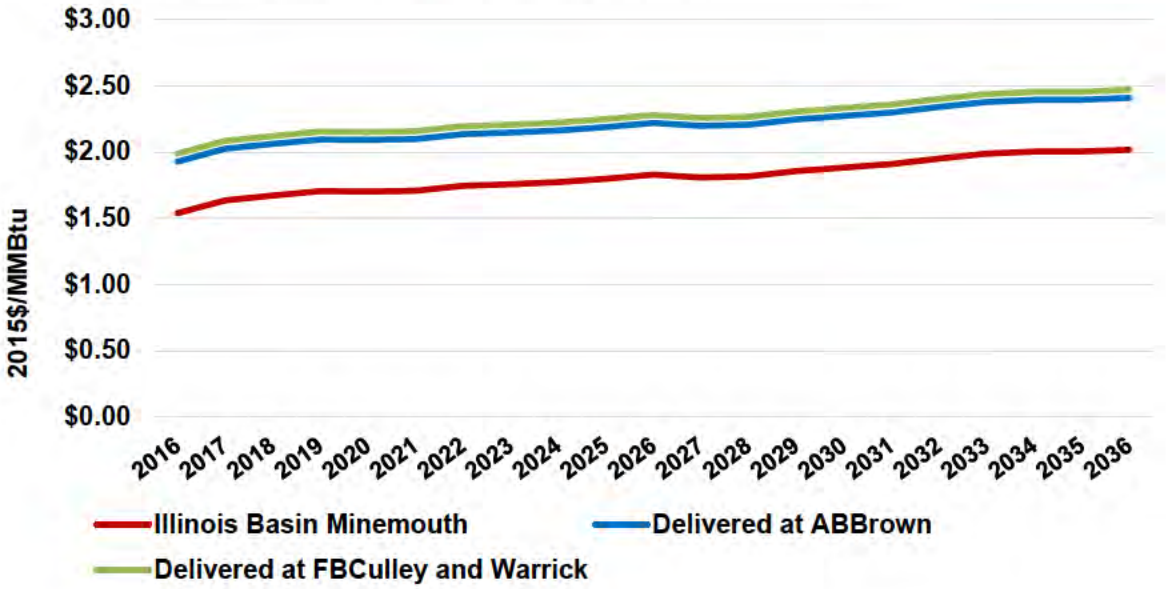
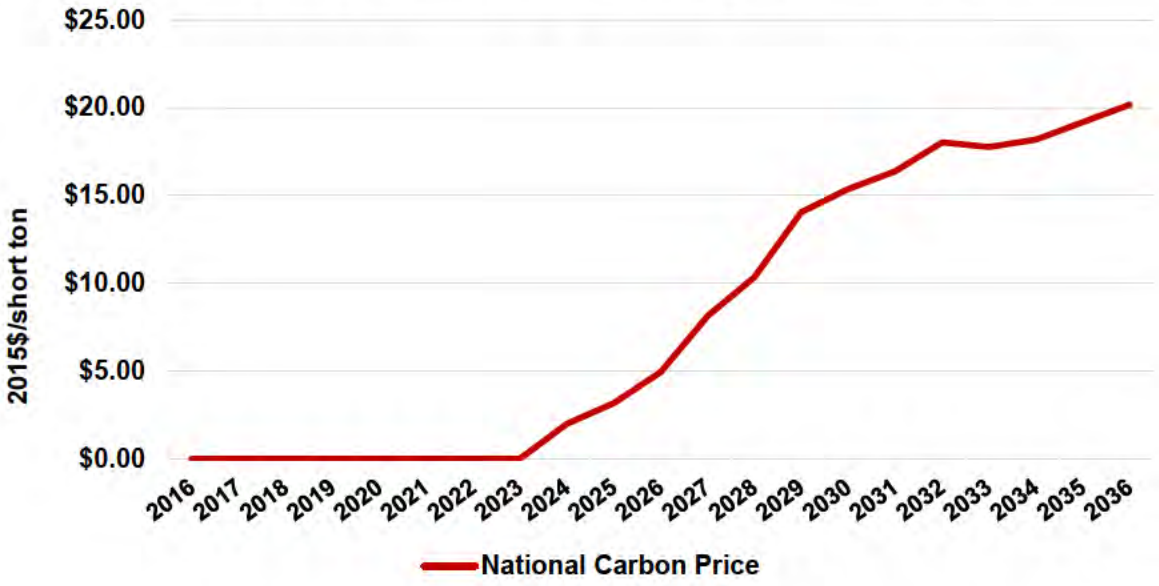
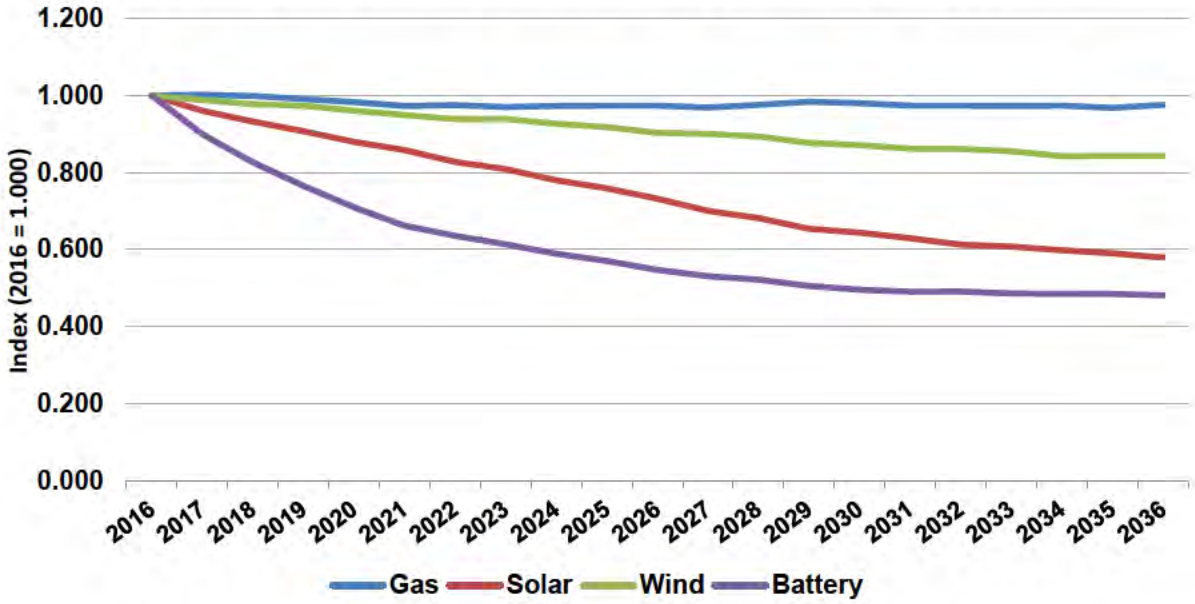


Figure 6.4 – Base Case Carbon Price Forecast (2015$/short ton)



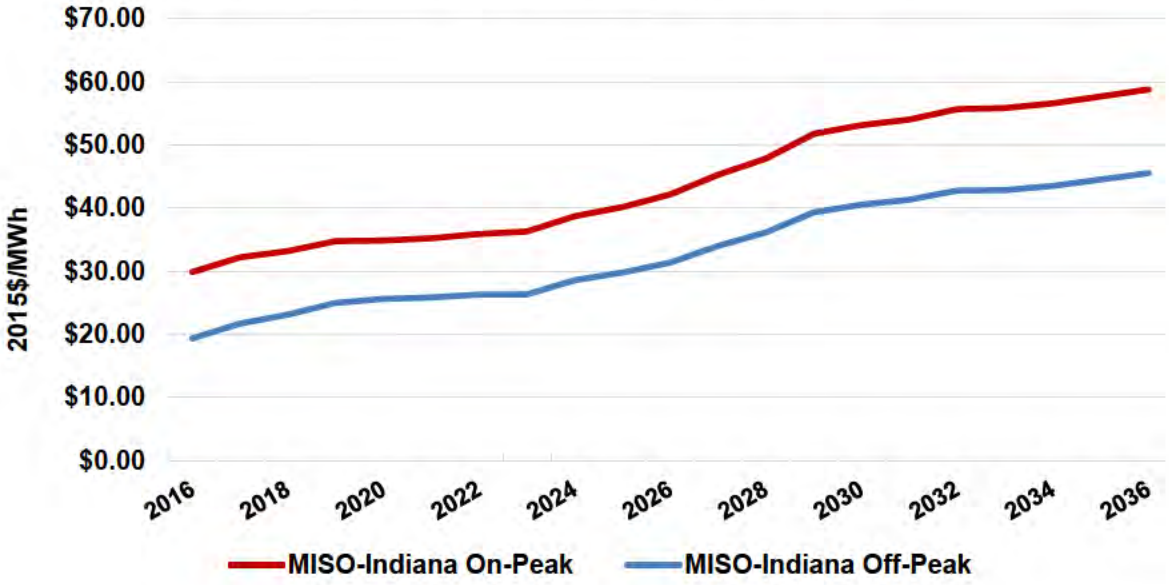
Current capital costs were developed by Burns & McDonnell, with a decline rate for each capital cost category (single cycle gas turbine, combined cycle gas turbine, solar, wind, and batteries) developed by Pace Global.

Figure 6.5 – Base Case Capital Cost Price Index Forecast (2016 = 1.000)



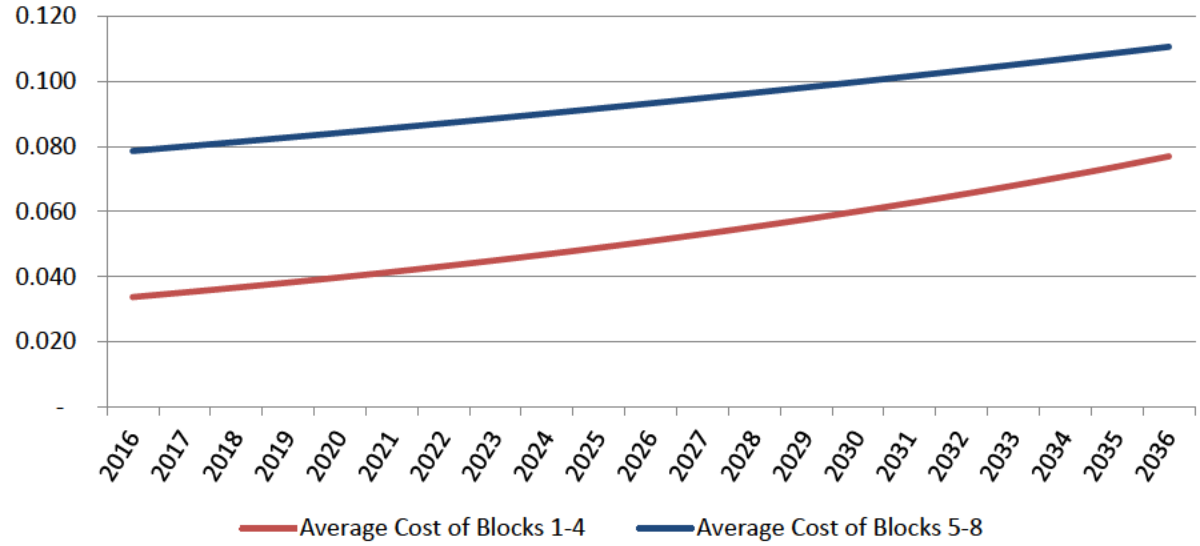
On- and off-peak power price forecasts were developed by Pace Global using the base case assumptions described above, together with Pace Global' s view of the greater MISO market, in the AURORAxmp power dispatch model.

Figure 6.6 – Base Case Power Price Forecast (2015$/MWh)



Levelized DSM costs were developed by Dr. Richard Stevie and described in detail in Section 5.2.3 DSM.

Figure 6.7 – Base Levelized Cost of DSM



6.1.2 Environmental Regulations

6.1.2.1 Effluent Limitations Guidelines (ELG)

On September 30, 2015, EPA published the final Effluent Limitations Guidelines rule (ELG). The rule sets strict technology-based limits for waste water generated from fossil fuel fired generating facilities and in particular, will force significant operational and technological changes at coal fired power plants. Below are the estimates used for IRP modeling.

AB Brown: ELG related changes include conversion to dry bottom ash, upgrades to the dry fly ash system, a new landfill that can handle scrubber product and ash, and a new lined pond to handle process water (~$115M).

FB Culley: Required plant upgrades include conversion to dry bottom ash, FGD waste water treatment, and access to a landfill that can handle small quantities of dry bottom ash (~$75M).

Warrick U4: The exact ELG status of the Warrick plant will not be determined until the next NPDES permit renewal in 2018. For purposes of the IRP only, Vectren has assumed required upgrades and costs similar to FB Culley since the units are of similar design and size (~$40M, Vectren's portion of the total $80M estimate).

6.1.2.2 Coal Combustion Residuals (CCR)

The Coal Combustion Residuals Rule (CCR) was finalized on April 17, 2015. The rule regulates the final disposal of CCRs which include fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs at a power plant that was generating electricity on the effective date of the rule (October 2015). The rule establishes operating criteria and assessments as well as closure and post closure care standards.

For AB Brown and FB Culley, it was assumed that ash ponds would be closed in place at the end of their useful life. The timing of the closures is dependent on continued need for the pond. For instance, if ELG related changes are made, such that the pond is no longer being used for ash storage, pond closure is then triggered. The base cost for the closures does not change regardless of future generation, and only the timing of the spend is affected in the modeling. Vectren has not historically utilized the ponds at the Warrick power plant for its share of the CCR generated by Warrick 4, and therefore is not liable for pond closure costs.

6.1.2.3 Clean Power Plan (CPP)

EPA finalized the Clean Power Plan that established carbon dioxide (CO_2) emission standards for a state's electric generating fleet in August 2015. States were given the discretion to set unit specific limits or adopt a mass-based or rate-based allowance trading program. The US Supreme Court issued a stay of the rule. It is not anticipated that final order on judicial review will come until 2017. After which, the state will develop the State Implementation Plan (SIP).

Vectren assumed the CPP would be upheld by the US Supreme Court, but the compliance would be delayed two years to 2024 due to the implementation delay caused by the stay. An average of currently available carbon costs was used for base case modeling. Note that the start dates for forecasts were adjusted to 2024 prior to averaging. More details can be found in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS.

To consider carbon (CO_2) emissions, Vectren assumed an emission allowance trading system with costs per short ton of emissions under all scenarios except the low regulatory scenario. Allowances were allocated based on Vectren's historical portion of CO_2 emissions relative to the state of Indiana totals for 2012. Allowances were based on the final Clean Power Plan (CPP) mass-based state targets. Vectren decreased the mass-based targets over time to reflect the interim and final targets of the rule. In all except the high regulatory scenario, the CPP interim period and final targets were delayed two years from the original start year (2022) in order to factor in delays associated with resolution of legal challenges pending before the United States Supreme Court.

6.1.2.4 316(b)

EPA issued their final rule regarding Section 316(b) of the Clean Water Act. The rule establishes requirements for cooling water intake structures (CWISs) at existing facilities.

This requirement applies to both FB Culley and Warrick 4. Standard fine mesh, fish friendly screens, and fish return systems were estimated to be $12-14M at FB Culley and $5-6M at Warrick 4 (Vectren's share).

6.1.3 Capacity Prices

The MISO capacity price has been difficult to predict as indicated by the volatile price history shown in Section 1.3.7, MISO. However, it is necessary for analysis purposes to have a capacity market price assumption to be included in the IRP modeling process. Some capacity will be bought or sold in practically every year due to the fact that load and planning reserve margin requirements vary incrementally from year to year while most supply side resources, such as generating units, come in large blocks with 30 to 55 year expected lifetimes. Vectren elected to use the Ventyx fall 2015 reference case MISO Indiana capacity price forecast for modeling purposes.

Figure 6.8 – Confidential Forecast Capacity Market Value (2015$/kW-yr)



6.1.4 Assumptions

Broadway Avenue Generating Station (BAGS) Unit 1 (as mentioned in Section 5.1.2, Natural Gas) has been mothballed and is earmarked for retirement in 2018. (47 years)

Broadway Avenue Generating Station (BAGS) Unit 2 (as mentioned in Section 5.1.2, Natural Gas) is earmarked for age related retirement in 2025. (44 years)

The Northeast Gas Turbine generating facility, NEGT 1 and NEGT 2, with capacities of 10 MW each, are currently scheduled to be retired from commercial operation in 2019. (55 years)

6.2 DEVELOPMENT OF ALTERNATE SCENARIOS

In order to develop several alternative scenarios for its IRP process, Vectren created a base case and several additional qualitative scenarios in its initial formulation. These scenarios were evaluated by a panel to estimate how key uncertainties (e.g., energy sales, gas prices) might fall relative to the base case. These estimates were quantified, averaged, and compared to Pace Global's independent estimates, which were closely aligned. Additionally, stakeholders provided Vectren with their list of possible uncertainties in a workshop held on April 7, 2016. Their inputs were considered and incorporated into the development of each alternate scenario.

These initial scenarios (base case plus 10 alternate scenarios) were then consolidated and reduced by Pace Global to a base case plus 6 alternate scenarios. The alternative scenarios were developed along three primary axes: regulatory, technological, and economic. Each axis is dichotomous, either being high or low, although there is only one technology scenario as technological innovation is assumed to either continue at the present rate or at an accelerated rate, but not at a "low" rate. From these three primary axes come five scenarios that provide a wide range of conditions in which to evaluate various portfolio planning strategies.

6.2.1 Description of Alternate Scenarios

As described in Section 2.3, DEFINE BASE CASE AND BOUNDARY SCENARIOS, the purpose of developing these "boundary" scenarios were to test a relevant range for each of the key market drivers on how various technologies are selected under boundary conditions. The specific conditions described in the following section are illustrative of the kinds of conditions that might generate values shown in the following

graphics. Values for the market drivers were based on an adjustment from the mean of a distribution and not a calculated value from that scenario.

6.2.1.1 High Regulatory

The High Regulatory scenario is characterized by a more heavily regulated path. The High Regulatory path is indicative of the following plausible circumstances relative to the base case:

- A much higher cost for compliance with the CPP, which begins on schedule in 2022, in part from less coordination among states that results in a mix of rate-based and mass-based compliance, but with many states not opting in to a national EPA backed program and in general more state-by-state command and control efforts for CO_2 emissions;
- More renewable adoption pushed through via mandates;
- Additional regulations on carbon on the horizon after 2030 that are higher than in the base case;
- Greater adoption of distributed generation in the form of solar and combined heat and power;
- Restrictions on fracking and fugitive methane emissions that limit gas supply growth, drive up gas prices, and result in an additional push and economic case for renewable energy; and
- Low economic growth that provides justification and room for greater regulation.

In the short-term (2016-2018), markets will not yet be characterized as “high regulatory” and will largely resemble the drivers in the base case. However, over the intermediate term some combination of the following might occur that results in the price trajectories shown below:

- The U.S. economy will continue to expand, albeit with signs that mid-term economic growth may be slower than in the base case. The customer base continues to grow, including among large C&I customers, with some initial

attention being paid to the contribution from large-scale industrial facilities to carbon emissions.

- Natural gas prices remain relatively low in the short-term, forcing operators to innovate rapidly to drive up efficiencies and drive down production costs or face bankruptcy. An ever greater share of U.S. gas production comes from shale gas, which is highly concentrated in Ohio, Pennsylvania, and West Virginia. This concentration of production renders U.S. supply more susceptible to short-term curtailments (freeze-offs) and longer-term economic downswings (and thus lower gas production out of this region).
- Coal prices remain depressed as in the base case, but with an economic outlook for coal-fired generation in the mid-term that appears to be increasingly regulated.
- Meanwhile, CO_2 prices in the California and RGGI markets begin to move upward in anticipation that these programs will be CPP compliant after 2022.
- Market penetration of solar and wind generation continues to grow at a fast rate, albeit still from a relatively small base, with state- and federal-level mandates supporting their implementation through relatively inefficient and costly market mechanisms. As a result, a full recovery of costs to maintain national transmission and distribution grids remains difficult, and underinvestment continues in modernizing the underlying power grid infrastructure.
- In the short-term, these market forces do not indicate an overly heavy interventionist hand from the state. However, they do presage a higher regulatory level to come in the medium- to long-term as the economy grows relatively weakly, market power prices rise, and the state intervenes in an attempt to stabilize markets.

In the medium-term (2019-2025), the following is representative of the high regulatory projections:

- At the beginning of the CPP compliance period in 2022, little progress has been made among states to opt into efficient national trading mechanisms. States seek

compliance individually or on a regional basis that results in the need for higher cost emission reductions and increases the overall compliance cost of the program.

- Further, the EPA could issue additional CPP reduction goals for the 2031 and beyond time period, which are significantly stricter than the current CPP. All of these developments lead to increased costs for CPP compliance that in turn lead to higher market power prices and a lower level of load growth as compared to the base case.
- Power markets are also constrained by higher gas costs stemming from increased regulation on natural gas fracking and fugitive methane emissions from distribution pipelines and drilling operations.
- Environmental concerns over fracked gas (e.g. induced seismicity, contaminated well sites) and a sustained public affairs campaign lead to national restrictions, higher production costs, and a lower supply base for natural gas.
- Coal-fired generation is highly disfavored due to ever-tightening restrictions on plant emissions, leading to lower coal prices than in the base case based on lax demand, but higher costs for coal-fired generation that lead to higher coal-fired plant retirements. Export restrictions on oil, gas, and coal are reinstated or increased.
- The U.S. economy undergoes another major market correction and resulting recession, leading to sweeping market interventions that include reforms such as mandated improvements to energy infrastructure whose costs are passed along to consumers. This leads to a high rate of retirement of coal plants, replaced by costly renewables that require commensurate and costly investment in energy storage. It also includes costly upgrades to transmission and distribution (T&D) infrastructure to guard against cyberattacks. Strong targets for distributed generation penetration, energy conservation, demand-side management, and energy efficiency lead to increased costs and higher electricity rates for existing energy company customers.

In the long-term (2026-2036), the high regulatory scenario enters into the 2030s at the same time as efforts to reduce carbon footprint become ever more intensified and target all areas of the traditional energy market.

- A new round of global climate talks is successful and includes binding targets, which precipitates an ever increasing regulatory role of the government in the energy sector, that help to keep CO_2 and power prices high.
- Toward the end of the forecast period, the scale of renewable penetration is such that costs begin to move downward once again as fuel costs become less important, and capital costs decline with massive economies of scale for renewable production and an efficient labor force experienced in distributed generation. The U.S. market experiences a period of moderate and sustained growth, which allows some breathing room in terms of new regulatory restriction, but not enough incentive to roll back existing restrictions, which continue to push high levels of coal retirements and renewable additions.

6.2.1.2 Low Regulatory

The low regulatory scenario was developed to establish a lower boundary condition on regulatory reform. Relative to the base case, this scenario is characterized by free market attitude in which few new regulatory restrictions are put forward and many of those that are currently in motion (e.g. CPP) are shelved. Regulations that do enter into force are implemented at lower cost than expected.

In the short-term (2016-2018):

- Political leaders shelve the national carbon regulatory scheme (the CPP).
- The U.S. economy continues to improve (as it does in the base case), which in turn leads to the beginnings of rising energy sales.
- Natural gas costs remain relatively low, as do coal prices, which help to constrain market power prices to the same moderate level as in the base case. Capital costs remain moderate as the commodity price rout continues and as wages grow only slowly.

The main difference between the outlook in this scenario and the recent past is that economic or forced retirements are expected to be lower than in the base case (in the medium-term). A strong economy, low fuel costs, and robust load growth help to sustain the existing generation fleet that includes coal plants. This period of efficient market operations helps to keep power prices on the lower side and stave off new regulatory interventions.

In the medium-term (2019-2025):

- The U.S. market continues to improve and grow which limits economic plant retirements and encourages additional deployment of advanced gas-fired generation to meet load growth.
- Although absolute emissions begin to rise again as the economy grows, per capita energy intensity declines, and as a result the CPP remains the only significant piece of regulation to move forward during this timeframe. Fuel prices remain moderate (gas) to high (coal).
- Commodity costs begin to rise once again as the global economy picks up steam, though not enough to move capital costs away from the base case forecast. Overall, the strength of the economy helps to limit the desire to intervene with any potential market corrections and new regulatory regimes.

In the long-term (2026-2036):

- Few new power market interventions are sought or required. Energy markets continue to work well, providing affordable electricity and fueling a sustained period of economic growth.
- However, this economic growth reverts to a more moderate level in the long-term, similarly moving load growth to a moderate level.
- Capital costs rise steadily in the healthy economy as interest rates are pushed higher by federal monetary policy makers. Retirements move to a more moderate level as older plants are forced to retire and capacity additions rev up to handle

these retirements as well as the continued economic growth (despite higher capital costs).

6.2.1.3 High Technology

The high technology scenario was constructed to be indicative of significant advances in energy storage technology, renewable energy deployment, emissions reduction and CO_2 removal technology, high efficiency gas-fired generation, and natural gas extraction productivity. Overall, there are significant developments in technologies that improve energy efficiency, which helps to mitigate the load growth that might otherwise be expected in a high technology scenario with robust economic growth.

In the short-term (2016-2018):

- The recent high pace of coal plant retirements continues (mostly due to MATS regulation but also for economic reasons), driven largely by initially low gas prices that create difficult economic conditions for coal-fired generation.
- The pace of economic expansion continues to grow as the U.S. economy becomes the lead driver of global economic health. However, this also begins to push interest rates higher with potential impact on future capital costs.
- Because fuel costs remain low initially (shale gas oversupply continues while coal demand remains soft), market power prices also remain muted despite moderate energy sales growth in an increasingly healthy U.S. economy.
- Low natural gas prices begin to have an effect on production, reducing the growth rate for new supplies, while the strong uptick in gas demand from LNG exports and other sectors helps to tighten the market and push gas prices higher in 2018.

In the medium-term (2019-2025):

- The main characteristic of the high technology scenario is that in the early 2020s timeframe a technology breakthrough occurs in the renewables market and possibly also in the storage market, such that the cost for renewables declines

dramatically, which in turn encourages a faster shift to renewables from fossil fuels.

- This breakthrough results in an incremental reduction in natural gas demand, in the latter half of the medium-term, as compared to the base case. Coal plant retirements continue at a relatively high rate. Whereas previously these retirements were driven primarily by competition with existing natural gas-fired generation, they are increasingly being replaced with renewables and high efficiency combined cycle gas turbine (CCGT) plants.
- Accordingly, the high rate of retirements and capacity additions/replacements continues into the medium-term. Many of the expected costs that are associated with CPP compliance are mitigated by advances in generation (gas and renewables), distribution, and storage technologies. Gas prices remain low despite somewhat tighter supply/demand dynamics, which prompts another wave of improvements in drilling and fracking technology and helps to keep gas prices at relatively low levels.
- The low gas prices are coupled with lower gas demand in the medium-term as renewables growth begins to pick up steam. Interest rates continue to move higher, which in turn pushes capital costs higher than in the base case.
- Distributed generation plays a much greater role in the high technology scenario, given advances in battery technology, gains in photovoltaic costs and efficiencies, and a more coordinated approach to managing variable wind generation across regional transmission organizations (RTO) and independent system operators (ISO).
- Given advances in battery technologies, there is a higher penetration rate of electric vehicles than in the base case. This increases load growth, but also allows for a more efficient distribution of resources as the growing fleet of vehicle batteries help to manage peak power load and power price volatility.

In the long-term (2026-2036):

- A well-functioning and expanding U.S. market helps to keep regulatory interventions beyond the CPP at a minimum.
- Fuel costs continue to remain relatively low.
- The pace of retirements and capacity additions continues in the high technology scenario, albeit slightly lower than otherwise would be with lower capital costs (as a result of interest rates that remain high). Most of the retirements would come from older gas plants (including single cycle gas turbine peakers) while most of the additions would come from residential and commercial solar, wind, CHP, and combined cycle gas turbine facilities. There are fewer feedback mechanisms at play in this scenario, as the technology improvements over time help to maintain low fuel and capital costs and keep the energy sector on a steady path of moderate growth.

6.2.1.4 High Economy

The high economy/market scenario was constructed to be indicative of a market that has a robust and growing U.S. economy keeping upward pressure on all of the major market outcome categories, including load growth, fuel costs, power prices, and capital costs. This growth is in the absence of a major technological breakthrough. Existing generation resources are needed to maintain this economic expansion, limiting the number of retirements while accelerating the number of capacity additions. While this scenario shares many of the attributes of the previous high technology scenario, the pace of technological innovation is not as dynamic, and therefore beneficial to keeping prices and costs in check. Regulations are similar to those in the base case.

In the short-term (2016-2018):

- The U.S. economy makes substantial gains in reducing the unemployment level while creating new jobs that bring discouraged workers back into the work force. The housing market continues to improve, as do the C&I sectors.

- Commodity costs remain low in the short-term, helping to fuel this period of continued economic expansion. All planned capacity additions move forward in a timely manner, while somewhat fewer coal plants announce a planned retirement due to economic or regulatory conditions. In the short-term, regulation continues in a business-as-usual manner.

In the medium-term (2019-2025):

- Outlook in this scenario begins with many positive indicators that continue into the medium-term. However, the expansion of the economy becomes a partial victim of its own success.
- Strong economic growth in the U.S. market helps to push energy sales higher, which in turn pushes underlying fuel and capital costs higher. A relatively strong feedback mechanism begins to assert itself under these circumstances, in which technology does not play as great a role in this scenario as it does in the high technology scenario. Accordingly, what began as very strong growth begins to become more restrained toward the end of the medium-term.
- Existing technology remains important in maintaining the high rate of load growth because technology does not necessarily play as large a role in this scenario. Accordingly, very few coal, gas, or other plants are retired for economic or regulatory reasons, while new plants are added on a relatively consistent basis.
- The CPP proceeds along the lines of the base case, with CO_2 costs at a similar level. Gas costs are incrementally higher, as are the costs for renewables.

In the long-term (2026-2036):

- Global economic activity begins to increase as developing markets such as India move to the forefront and drive growth.
- Global growth begins to apply upward pressure to global LNG and coal costs as well as commodity costs for materials, which in turn drives up market power prices here in the United States.

- Energy sales growth remains strong, as do capacity additions, but tighter global markets put upward pressure on several of the other market outcomes.
- Long-term outlook in the high economy/market scenario begins to push toward an era of high prices, high costs, high capacity additions, and high load growth. Given that the economy is doing well in this scenario in the long-term, market regulators feel they have greater latitude to implement additional regulations. This provides a modest feedback loop to slightly dampen U.S. GDP growth over time.

6.2.1.5 Low Economy

The low economy/market scenario is characterized by sluggish economic growth both domestically and globally, including (in the short-term) important growth markets like China, Europe, and Brazil. While some conditions are favorable to the U.S. economy, including low fuel costs, most indicators point toward headwinds for growth in the GDP level. Moderate CO_2 prices and low load growth help to keep market power prices on the low end of the scale, which in turn keep capacity additions low. Market regulators have less latitude to implement new regulations, as the economy cannot afford them in this low economy scenario.

In the short-term (2016-2018):

- The U.S. economy begins this period at a relatively good growth rate, but the rest of the world does not fare as well, which begins to weigh on the U.S. economy.
- As a result, load growth begins to slow gradually as U.S. manufacturers and exporters curtail operations, which in turn leads to low market power prices.
- Low gas prices remain low as demand dries up (incrementally) even while supply remains healthy.

In the medium-term (2019-2025):

- As the global economy continues to stagnate or degrade, the U.S. economy also begins to be affected negatively. GDP growth is less than half a percent, which

particularly hurts the power sector given the strong role that energy plays in fueling economic growth (though efficiency gains have been muting this role of late).

- With little to no growth in energy sales, few new plants are built and plants continue to retire as they reach the end of their technical and economic lives. Fuel costs remain relatively low, given the lack of demand.
- Capital costs remain moderate as interest rates maintain a modest level, as the policy makers are reluctant to return to an era of artificially low interest rates.

In the long-term (2026-2036):

- By the 2030's, the world market is slowly coming out of its slump, but recovery is slow as progress is held back by strong global adherence to emissions targets set forth in climate negotiations.
- Low fuel prices continue, albeit slightly higher as demand eventually responds to sustained low prices. Overall, in the long-term the low economy/market scenario begins to revert back to resemble, in part, the base case with more moderate levels of market outcomes and drivers.

6.2.1.6 Base Large Load Addition

This scenario adds 100 MWs of load beginning in 2024 to the base forecast. All else is equal to the base scenario.

6.2.2 Coordinated Forecasts for Alternate Scenarios

6.2.2.1 Methodology

A very structured and coordinated approach for developing alternate scenarios was undertaken as part of this IRP process. It has been observed that future markets are driven principally by economic forecasts, regulations, and technological change. Accordingly, a set of alternate scenarios was developed around the base case that include a "low and a high regulatory" case, a "low and a high" economic case, and a

"high technology" case. Each of these scenarios has an internally consistent narrative. For example, the "high regulatory" case is associated with both a more strict Clean Power Plan case, plus fracking restrictions, or other water usage issues that would limit shale gas development, and more stringent regulations on coal.

This methodology provides a useful starting point for integrated forecasts that are fully developed and consistently applied. Under each of these scenarios, a perspective was developed on how key variables such as load growth, fuel prices (e.g. coal and gas prices), emission prices, and capital costs for different technologies, retirements, and new builds are expected to move relative to the base case forecasts in the short term, medium term, and long term. These narratives were converted to a directional change for each variable, and then actual values were developed in a consistent manner.

These alternate scenarios were developed to be plausible, not necessarily highly probable. They are intended to provide boundary conditions against which to test each portfolio or investment strategy. A description of the development of these integrated forecasts for each of the key variables is provided in this document. For the development of these scenarios, stochastic distributions of each of the key variables (e.g. load, gas prices, technology costs, etc.) were developed, with select values that are either one standard deviation above or below the base case values for that variable. In this way, a consistent methodology was applied across each of the integrated scenarios, by creating both a directional variable movement and a consistent quantified value for the variable that is consistent with the description of that alternate scenario.

A hybrid approach that combines a deterministic forecast for key market drivers together with probabilistic stochastics was used to inform the characterization of uncertainty. Stochastic distributions that reflect a combination of historical data and informed judgment tend to capture "black swan events" that are impossible to forecast, but tend to occur quite frequently. Some variables, like carbon regulations, have no historical data and others, like gas prices, have had fundamental market changes that

will influence the future differently from the past. Accordingly, a hybrid approach combined with expert judgment by market consultants was used to develop and inform the alternate scenarios.

6.2.2.2 Model Inputs

The following graphs illustrate the key market driver inputs across all of the alternate scenarios.

Figure 6.9 – Vectren Total Load (GWh) and Peak Load (MW) Alternate Scenarios

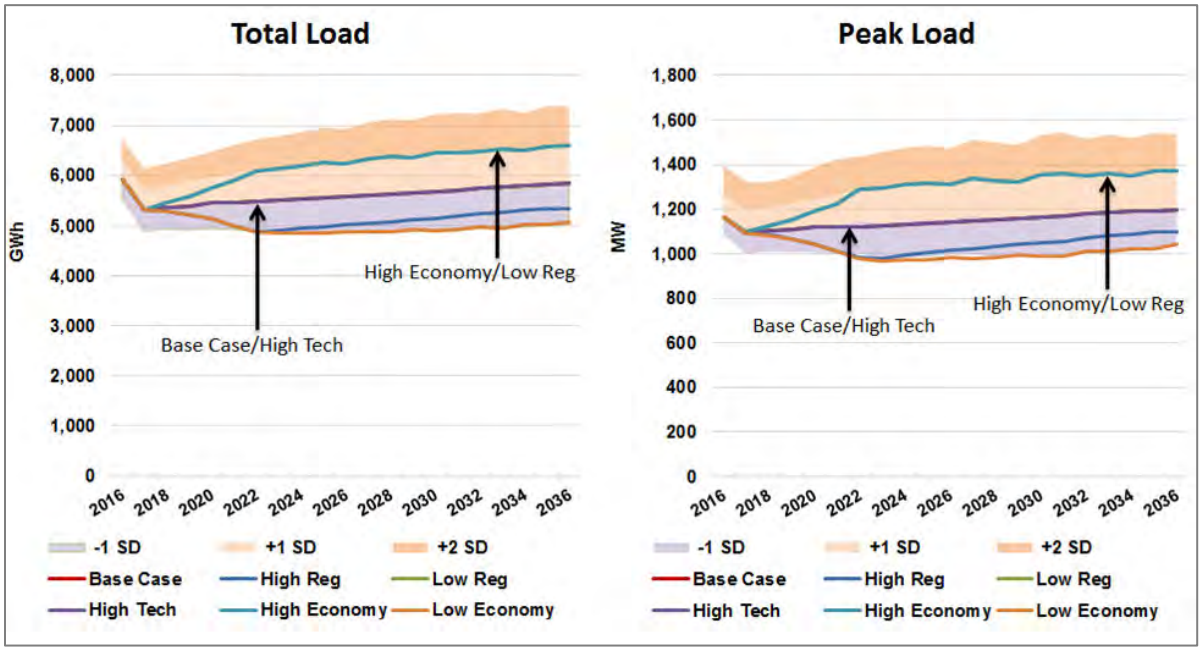


Figure 6.10 – Coal Alternate Scenarios (2015$/MMBtu)

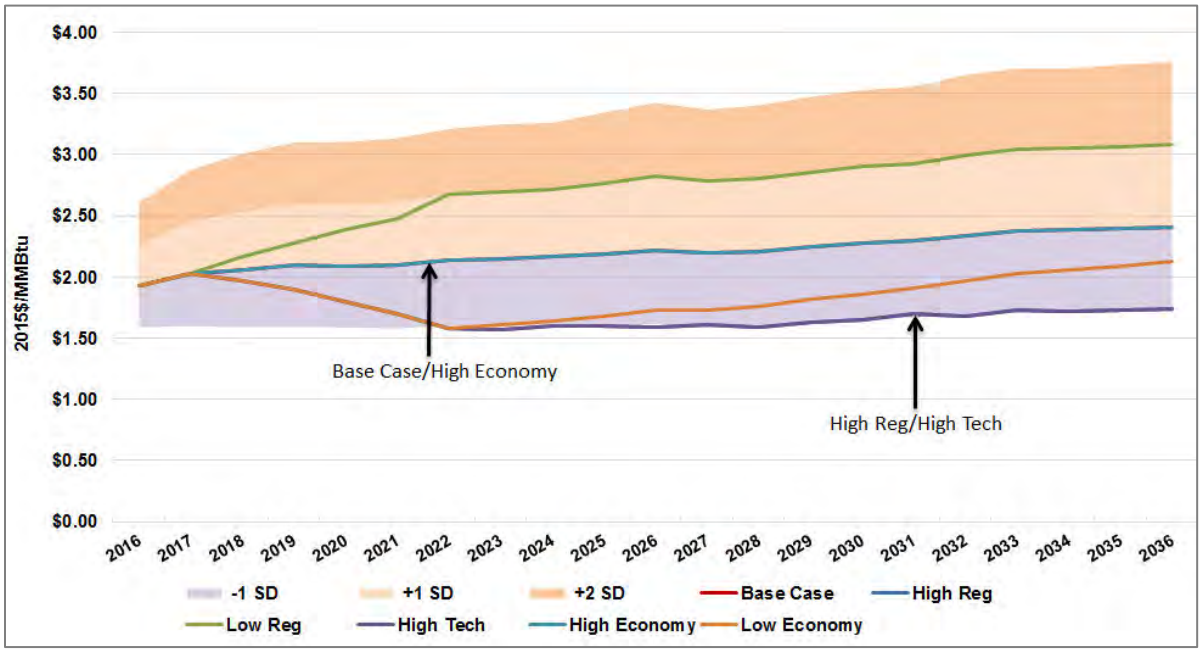
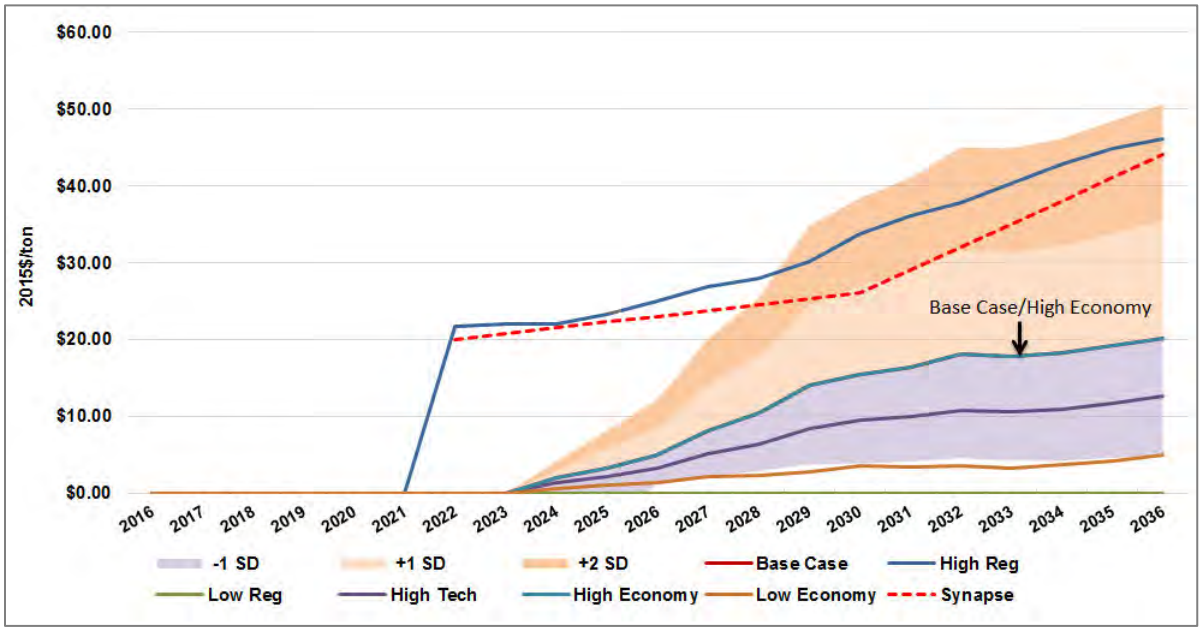


Figure 6.11 – Carbon Alternate Scenarios (2015$/ton)[48]



[48] Note that Synapse refers to the Mid Case on page 8 (adjusted for 2024 start date) from Spring 2016 National Carbon Dioxide Price Forecast, Updated March 16, 2016, Synapse Economics Inc., http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf

Figure 6.12 – Natural Gas (delivered to Indiana) Alternate Scenarios (2015$/MMBtu)

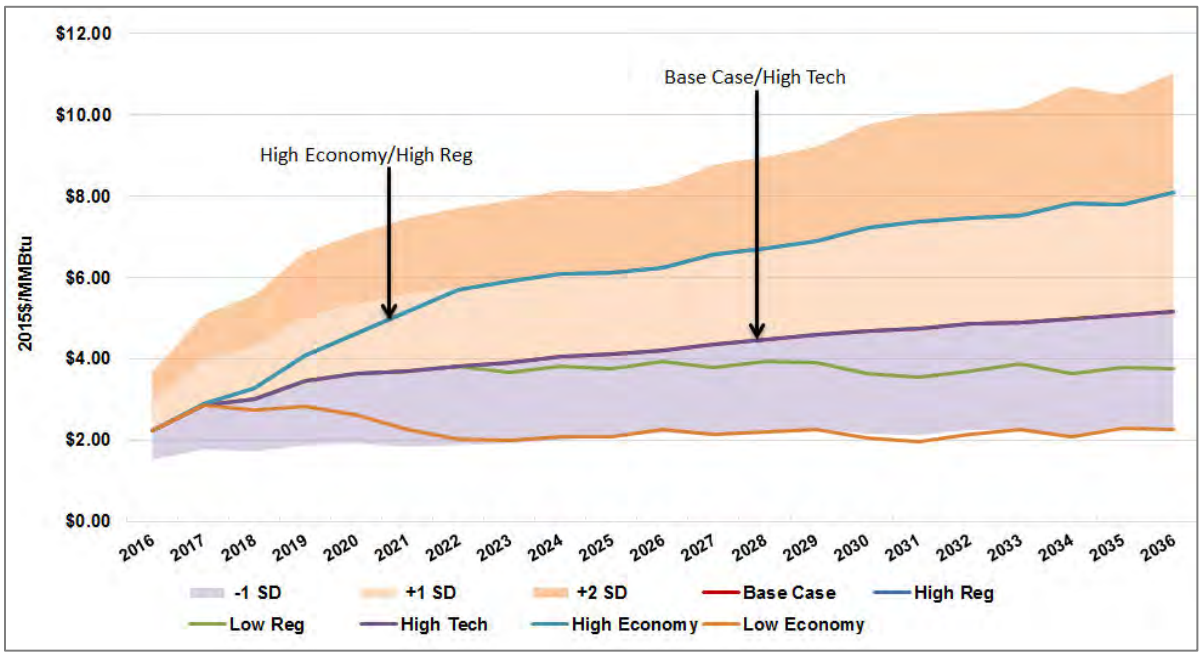


Figure 6.13 – Indiana Hub On- and Off-Peak Power Prices Alternate Scenarios (2015$/MWh)

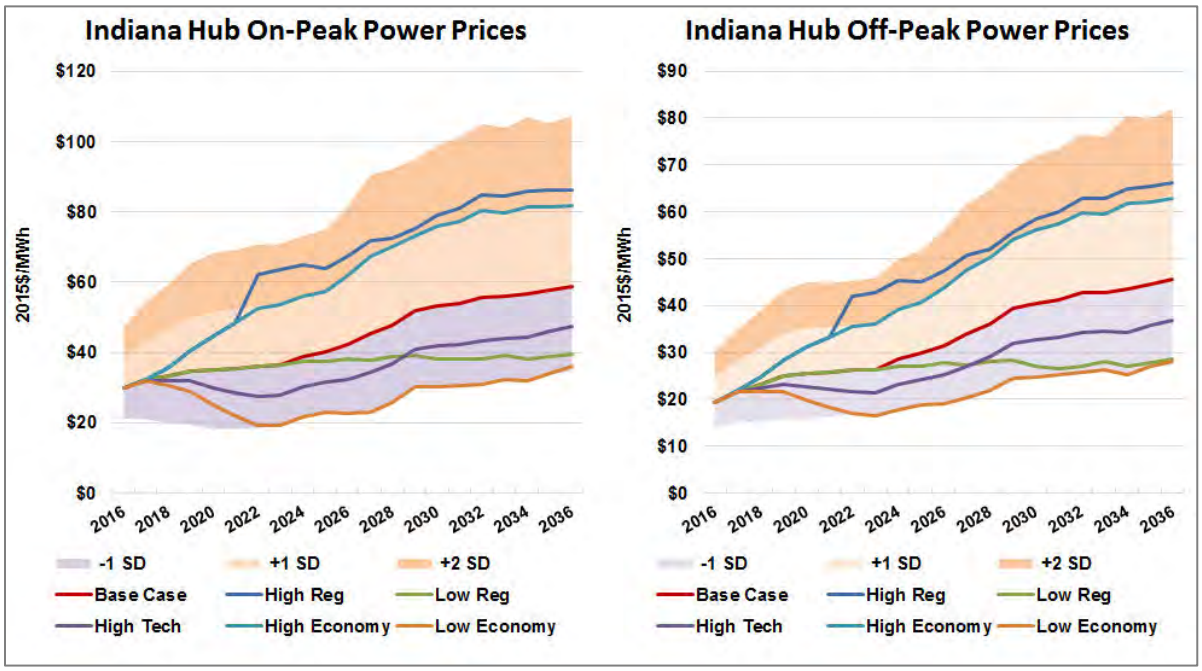


Figure 6.14 – Gas-Fired Capital Costs Alternate Scenarios (Index, 2016 = 1.000)

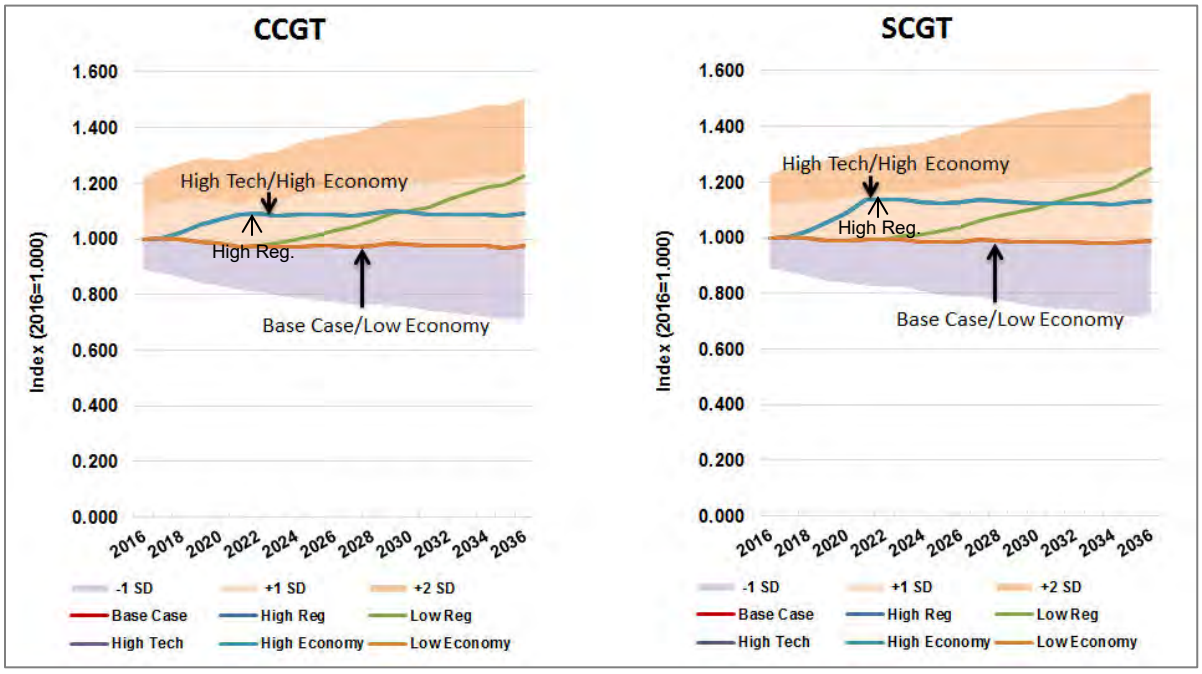


Figure 6.15 – Solar and Wind Capital Costs Alternate Scenarios (Index, 2016 = 1.000)

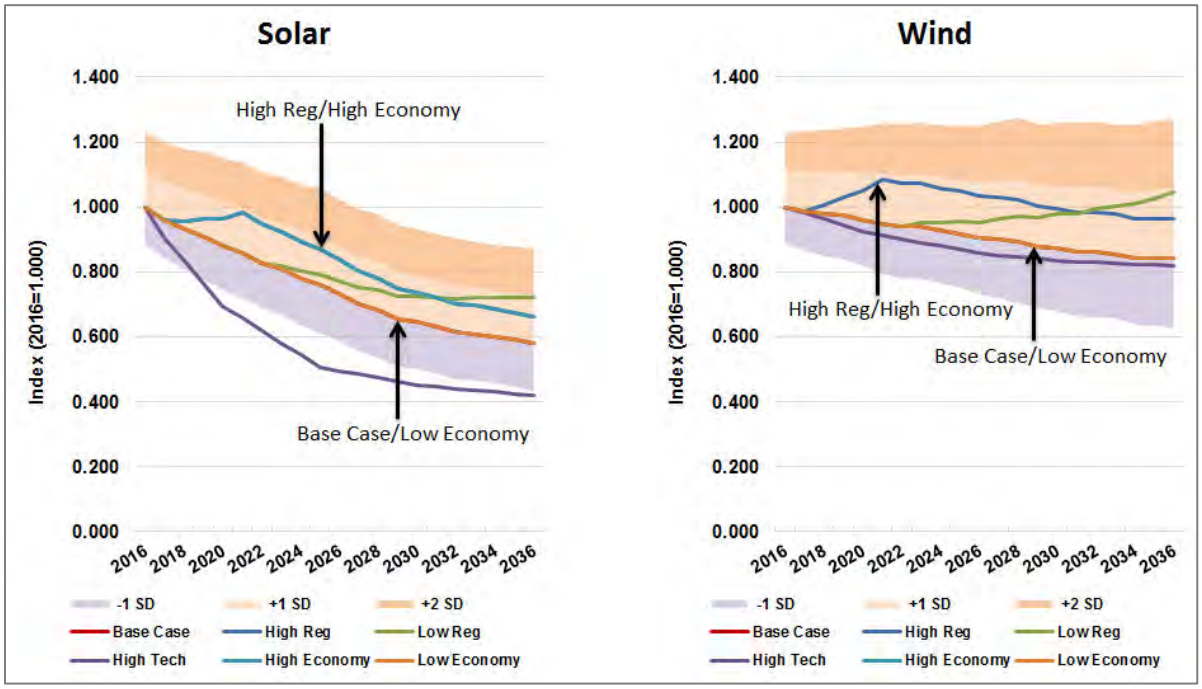
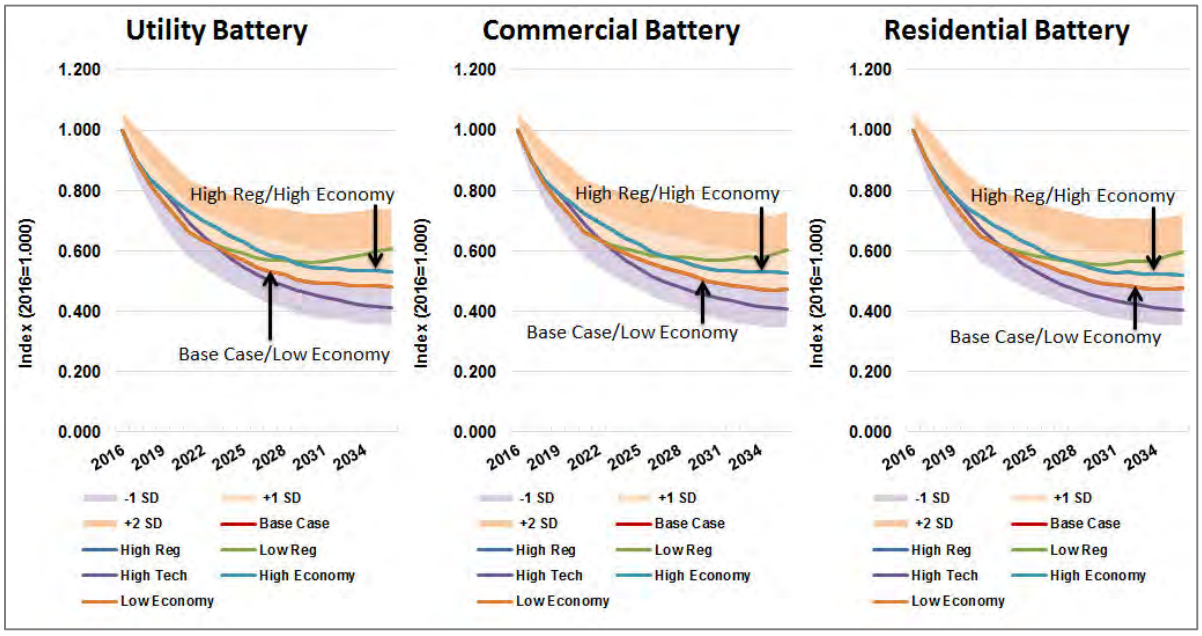


Figure 6.16 – Battery Capital Costs Alternate Scenarios (Index, 2016 = 1.000)



SECTION 7
SCREENING ANALYSIS

7.1 DEVELOP PORTFOLIOS

7.1.1 Optimized Portfolios

7.1.1.1 Model Description

Vectren continues to use the Strategist modeling software from ABB Group (formerly Ventyx), as it has in its last several IRP studies. This software has traditionally been used by some of the other Indiana utilities as well as utilities in other states. The modeling performed by Vectren provides important information to evaluate potential future resource needs.

Strategist is a strategic planning system that integrates financial, resource, marketing, and customer information. Strategist is able to simultaneously consider all aspects of integrated planning at the level of detail required for informed decision making. Strategist handles production costing, capital expenditures and recovery, financial and tax implications, and optimization all within one software system.

An optimization method has three elements: an objective, constraints, and alternatives. For the electric integration process, the three elements can be summarized as follows:

7.1.1.2 Objective

The objective of the analysis was to determine the optimal resource plan by minimizing the net present value (NPV) of customer costs. For the purposes of this discussion, the planning period NPV is defined as the net present value of operating costs including fuel, related emissions, and capital costs. Power purchases and sales are also included in the NPV analysis for the 20 year period, 2017 through 2036. NPV numbers were developed by integrating the various scenario assumptions into the optimization model. The generation options within the scenarios, along with unit retirements, additional DSM, and purchasing capacity from the market were compared against the capacity needs of the scenario yielding seven optimized low cost NPV plans.

7.1.1.3 Constraints

The primary constraint was to maintain a minimum planning reserve margin (PRM). MISO has moved to an unforced capacity (UCAP) PRM in the last couple of years. The UCAP accounts for the amount of installed capacity (ICAP) or nameplate capacity available at system's megawatt peak hour of the peak day after discounting for the time that the generating facility is not available due to historical outages such as maintenance and repairs. The UCAP PRM is subject to change each year depending on MISO's projected need and based on annual system reliability studies. For the planning year 2016/2017, MISO set forth a UCAP PRM of 7.6%. This means that Vectren must maintain at least 7.6% over the peak demand of its customers on a UCAP basis coincident to the MISO system peak. The goal is to determine the minimum planning reserve margin that would result in the MISO system experiencing a loss of load event less than one day every ten years. Other constraints include the project development and build times for new construction alternatives, transmission import constraints, reliability considerations, and the characteristics of existing resources and demand.

7.1.1.4 Alternatives

A broad array of alternative generation and DSM was included within the optimization analysis. The full range of supply-side resource alternatives were identified and discussed in Section 5, RESOURCE OPTIONS.

7.1.1.5 Results

There were a number of non-optimized portfolio shutdown decisions that were fixed due to age or other related issues including the following:

- End Warrick 4 joint operations mid-2020 (132 MW UCAP)
- Northeast 1 and 2 by end of 2018 (18 MW UCAP)
- BAGS 2 by end of 2024 (58 MW UCAP)

Additionally, a 4 MW solar plant is assumed to be operational by 2018. This is representative of 4-6 MWs of several energy company owned solar projects that are expected to be in place by this time, including:

- 2 MW universal solar power plant with a 1 MWh battery storage system
- solar plant with the City of Evansville, details of which are expected to be finalized in the first quarter 2017, and
- other potential project discussions (on-going).

Under all scenarios, additional resources were not selected until joint operations cease at Warrick 4, causing a planning reserve margin shortfall. At the end of 2023, economic shutdown of coal units occurred under each scenario. A 2x1 combined cycle gas turbine was selected to replace the retiring coal capacity. Certain portfolios selected a simple cycle gas turbine in addition to the combined cycle gas turbine. See the optimized and deterministic portfolio tables in Technical Appendix Attachment 7.1 IRP Portfolio Summary Report for more details. For a graphical representation of each portfolio see Technical Appendix 7.2 Balance of Loads and Resources. Detailed Strategist model information can be found in Confidential Attachment 7.3 Portfolio Input-Output Report.

In the **Base Scenario (aka Gas Heavy) Portfolio**, market capacity purchases occur through 2023. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) and a 1xF-class SCGT with an annual base load capacity of 220 MWs. Some market capacity purchases and solar capacity installations begin in 2032 and continue through 2036.

Figure 7.1 – Base Scenario (aka Gas Heavy) Portfolio

	(B) Base Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (68-73 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023 (77 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW)
2030-2036	**New** 2032-2036 (1-9 MW Market Capacity) 36 MW Solar

In the **Base + Large Load Scenario Portfolio**, there is 1% EE (2018-2036), market capacity purchases through 2023, and 4 MW of DR each year through 2024. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and are replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) and a 1xF-class SCGT with an annual base load capacity of 220 MWs. Market capacity purchases begin again in 2030, with 50 MW of solar in 2032 and 9 MW solar in 2035 and 2036.

Figure 7.2 – Base + Large Load Scenario Portfolio

	(C) Base + Alternate Load Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4MW Solar 2020-2022 (26-43 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (19 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW) 2023-2029 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (1-9 MW Market Capacity) 68 MW Solar 2030-2036 1.0% Energy Efficiency

The **High Regulatory Scenario Portfolio** is characterized by 1% EE (2018-2036), 4 MW solar in 2018, and market capacity purchases beginning in 2020. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 200 MW of wind come online in both 2030 and 2031, with significant market capacity purchases in 2030 through 2036.

Figure 7.3 – High Regulatory Scenario Portfolio

	(D) High Reg. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (39-47 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (889 MW) 2023-2029 (28-106 MW Market Capacity) 2023-2029 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (72-100 MW Market Capacity) 400 MW Wind 2030-2036 1.0% Energy Efficiency

The **Low Regulatory Scenario Portfolio** has a market capacity purchase of 43 MW in 2020, 1% EE (2018-2036), and the installation in 2021 of a 1xF-class SCGT with an annual base load capacity of 220 MW. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). A second 1xF-class SCGT with an annual base load capacity of 220 MW is installed in 2025.

Figure 7.4 – Low Regulatory Scenario Portfolio

	(E) Low Reg. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020 (43 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency) Simple Cycle Gas Turbine (220 MW) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW) 2023-2029 1.0% Energy Efficiency
2030-2036	2030-2036 1.0% Energy Efficiency

The **High Economy Scenario Portfolio** includes a market capacity purchases beginning in 2020, 2% EE (2018-2036), and the installation in 2022 of a 1xF-class SCGT with an annual base load capacity of 220 MW. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down, replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 9 MW solar come online in 2027 and substantial wind is built 2030-2036.

Figure 7.5 – High Economy Scenario Portfolio

	(F) High Economy Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 8 MW Demand Response 2020-2021 (10-27 MW Market Capacity) 2018-2022 (2.0% Energy Efficiency) Simple Cycle Gas Turbine (220 MW)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 12 MW Demand Response Combined Cycle Gas Turbine (889 MW) 9 MW Solar 2023-2029 2.0% Energy Efficiency
2030-2036	**New** 400 MW Wind 2030-2036 2.0% Energy Efficiency

The **Low Economy Scenario Portfolio** shows market capacity purchases 2020 through 2036. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 9 MW and 50 MW of solar come online in 2035 and 2036, respectively.

Figure 7.6 – Low Economy Scenario Portfolio

	(G) Low Economy Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (68-73 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023-2029 (67-155 MW Market Capacity) 20 MW Demand Response Combined Cycle Gas Turbine (889 MW)
2030-2036	**New** 2030-2036 (161-188 MW Market Capacity) 59 MW Solar

Finally, the **High Technology Scenario Portfolio** includes up to 91 MW of market capacity purchases through 2023. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking), as well as a 1xF-class SCGT with an annual base load capacity of 220 MW. Minimal market capacity purchases occur in 2035 and 2036.

Figure 7.7 – High Technology Scenario Portfolio

	(H) High Tech. Scenario
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (82-87 MW Market Capacity)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2023 (91 MW Market Capacity) Combined Cycle Gas Turbine (889 MW) Simple Cycle Gas Turbine (220 MW)
2030-2036	**New** 2032-2036 (1-10 MW Market Capacity) Battery 10 MW / 40 MWh 9 MW Solar

7.1.2 Stakeholder Suggested Portfolios

In addition to the scenario optimized portfolios, Vectren solicited input from public stakeholder attendees during the second public stakeholder meeting for two additional portfolios. These stakeholder portfolios include less combined cycle gas capacity additions (331 MW) compared to the other portfolios, 1,000-1,200 MW of wind capacity additions, 804-904 MW of solar capacity additions, 100-200 MW of battery storage capacity, and 30 MW of CHP capacity. Both stakeholder portfolios see 1,061 MW of coal capacity retirement, similar to the other portfolios, but fewer capacity market purchases. Energy efficiency plays a relatively larger role in the two stakeholder portfolios.

The **Stakeholder Portfolio** was developed with input from attendees during the second stakeholder meeting. It is characterized by 2% EE (2018-2036), market capacity purchases through 2021, and 4 MW of DR each year 2020 through 2024. In 2024, AB Brown Units 1 & 2 are shut down, there is partial ownership of a 1x1 CCGT F.05 (50%), 500 MW solar PV and 800 MW wind are installed, and 30 MW of combined heat & power is installed. Ten (10) 10MW/40MWh batteries come online in 2030. In 2035, FB Culley Units 2 & 3 are shut down, 200 MW wind and 400 MW solar PV comes online, and there is partial ownership of a 1x1 CCGT F.05 (25%).

Figure 7.8 – Stakeholder Portfolio

	(I) Stakeholder Portfolio
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2021 (6-23 MW Market Capacity) 2018-2022 (2% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (50%) – 220 MW 8 MW Demand Response 2% Energy Efficiency 500 MW Solar PV 800 MW Wind Combined Heat & Power (30 MW)
2030-2036	**Retirement** Retire FB Culley 2 & 3 (360 MW) **New** Combined Cycle Gas Turbine (25%) - 110 MW 2% Energy Efficiency 400 MW Solar PV 200 MW Wind 100 MW Battery

The second stakeholder portfolio [**Stakeholder Portfolio (Cease Coal 2024)**] is similar to the previous stakeholder portfolio, except that in 2024 FB Culley Units 2 & 3 are shut down rather than in 2035. In addition in 2024, there is partial ownership of a 1x1 CCGT .05 (75%), 8x100 MW solar PV and 6x200 MW wind are installed, 30 MW of combined heat & power is installed, and ten (10) 10 MW/40 MWh batteries come online.

Figure 7.9 – Stakeholder Portfolio (Cease Coal 2024)

	(J) Stakeholder Portfolio Cease Coal 2024
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2021 (6-23 MW Market Capacity) 2018-2022 (2% Energy Efficiency) 12 MW Demand Response
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (75%) - 330 MW 8 MW Demand Response 2% Energy Efficiency 800 MW Solar PV 1,200 MW Wind Combined Heat & Power (30 MW) 100 MW Battery
2030-2036	**New** 2% Energy Efficiency 100 MW Battery 2036 (3 MW Market Capacity)

7.1.3 Balanced Energy Portfolios

Economic modeling considers a wide range of theoretical possibilities, but does not necessarily account for all potential possibilities or real world outcomes, and therefore judgment must also be included in developing portfolios. In other words, an optimized portfolio may not be the best solution given future risks and uncertainties. In order to test a wide range of possible portfolios, Vectren included a business as usual portfolio and developed several balanced energy mix portfolios to be tested in the risk analysis.

The **Business as Usual Portfolio** represents a continuation of the current configuration of Vectren coal generating assets supplemented by market capacity purchases and a small measure of demand response (4 MW) 2020-2024. In 2024, a 1xF-class SCGT with an annual base load capacity of 220 MW comes online. Apart from small market capacity purchases in 2035-2036, the portfolio sees only minimal changes after the SCGT capacity comes online.

Figure 7.10 – Business as Usual Portfolio

	(A) Business as Usual (Continue Coal)
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4MW Solar 2020-2022 (60-63 MW Market Capacity) 12 MW Demand Response CCR Compliance at Brown & Culley
2023-2029	**Retirement** Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (60 MW Market Capacity) Simple Cycle Gas Turbine (220 MW) **Upgrade** ELG Compliance at Brown & Culley
2030-2036	**New** 2035-2036 (4-9 MW Market Capacity)

The **FBC3, Fired Gas, & Renewables Portfolio** is characterized by market capacity purchases that occur 2020-2023, as well as blocks of energy efficiency at 1% (2018-2020), 0.75% (2021-2026), and 0.5% (2027-2036). AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). 50 MW of wind and 9 MW of solar come online in 2027.

Figure 7.11 – FBC3, Fired Gas, & Renewables Portfolio

	(K) FB Culley 3, Fired Gas, & Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 4 MW Solar 2020-2022 (42-47 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 Retire Broadway Avenue Gas (65 MW) **New** 4 MW Demand Response Combined Cycle Gas Turbine (889 MW) 2023 (37 MW Mkt Capacity) 50 MW Wind 9 MW Solar 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 0.50% Energy Efficiency

The **FBC3, Fired Gas, Early Solar, & EE Portfolio** is similar to the previous portfolio, except that market capacity purchases are lower through 2023 and 50 MW of solar comes online in 2019. AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking). In addition, there are no renewable additions in 2027 as in the previous portfolio.

Figure 7.12 – FBC3, Fired Gas, Early Solar, & EE Portfolio

	(L) FB Culley 3, Fired Gas, Early Solar, & Energy Efficiency
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (23-28 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 Retire Broadway Avenue Gas (65 MW) **New** Combined Cycle Gas Turbine (889 MW) 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) 22 MW Market Capacity **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 0.50% Energy Efficiency

The **FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio** is similar to the previous portfolio, except that market capacity purchases are lower through 2023 and 4 MW of demand response is seen through 2024. AB Brown Units 1 & 2 as well as FB Culley Unit 2 are shut down (FB Culley Unit 3 continues) and replaced by a 2x1 F-class CCGT at AB Brown with an unfired annual base load capacity of 700 MW. Beginning in 2030, market capacity purchases and solar power plants help to meet future demand requirements.

Figure 7.13 – FBC3, Unfired Gas .05, Early Solar, EE, & Renewables Portfolio

	(M) FB Culley 3, Unfired Gas .05, Early Solar, Energy Efficiency, & Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (11-24 MW Market Capacity) 2018-2020 (1.0% Energy Efficiency) 2021-2022 (0.75% Energy Efficiency) **Upgrade** CCR Compliance for Culley 3
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 (90 MW) Retire Broadway Avenue Gas (65 MW) **New** 8 MW Demand Response 2023 (5 MW Market Capacity) Combined Cycle Gas Turbine (700 MW) 2023-2026 (0.75% Energy Efficiency) 2027-2029 (0.50% Energy Efficiency) **Upgrade** ELG Compliance for Culley 3
2030-2036	**New** 118 MW Solar 2030-2036 (2-10 MW Market Capacity) 0.50% Energy Efficiency

The **Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio** includes market capacity purchases 2020-2022, 4 MW of DR each year 2020-2024, and blocks of energy efficiency at 1% (2018-2036). 50 MW of solar comes online in 2019. In 2024, AB Brown Units 1 & 2 as well as FB Culley Units 2 & 3 are shut down and replaced by a 2x1 F-class CCGT at AB Brown with an unfired annual base load capacity of 700 MW and a 1xF-class SCGT with an annual base load capacity of 220 MW. Some market capacity purchases and a significant amount of solar capacity installations begin in 2025 and continue through 2036. Total solar capacity through 2036 equals 272 MW.

Figure 7.14 – Unfired Gas Heavy with 50 MW Solar in 2019 Portfolio

	(N) Unfired Gas Heavy with 50 MW Solar in 2019
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (7-24 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2025-2029 (3-10 MW Market Capacity) 8 MW Demand Response Combined Cycle Gas Turbine (700 MW) Simple Cycle Gas Turbine (220 MW) 118 MW Solar 1.0% Energy Efficiency
2030-2036	**New** 2030-2036 (3-9 MW Market Capacity) 100 MW Solar 1.0% Energy Efficiency

The **Gas with Renewables Portfolio** is similar to the previous portfolio, except that in 2024 an 889 MW 2x1 F-class CCGT at ABB with a duct-fired capability (690 MW of 24/7 power and 199 peaking) comes online. 331 MW of solar capacity is installed throughout the forecast period.

Figure 7.15 – Gas with Renewables Portfolio

	(O) Gas Portfolio with Renewables
2016-2022	Exit Joint Operations Warrick 4 Coal (150 MW) **Retirement** Retire Northeast 1 & 2 Gas (20 MW) **New** 12 MW Demand Response Energy Efficiency Plan 2016-2017 54 MW Solar 2020-2022 (3-24 MW Market Capacity) 2018-2022 (1.0% Energy Efficiency)
2023-2029	**Retirement** Retire AB Brown 1 & 2 (490 MW) Retire FB Culley 2 & 3 (360 MW) Retire Broadway Avenue Gas (65 MW) **New** 2025-2029 (2-9 MW Market Capacity) 8 MW Demand Response Combined Cycle Gas Turbine (889 MW) 168 MW Solar 1.0% Energy Efficiency
2030-2036	**New** 2030-2034 (4-10 MW Market Capacity) 109 MW Solar 1.0% Energy Efficiency

7.2 EVALUATE PORTFOLIO PERFORMANCE

7.2.1 Uncertainty (Risk) Analysis

The process for addressing uncertainty in long-term resource planning studies requires an integrated framework that takes into account markets for natural gas, coal, oil, and other fuels as well as capital costs for new generation (both fossil-fuel units and renewables) and supply/demand dynamics affected by environmental regulations and uncertainties around these regulations. To capture this variability of market conditions, Pace Global employed a stochastic analysis that provides a wide range of potential market outcomes for the study-period. These outcomes include variables such as energy prices, portfolio costs, and revenues from specific generation assets.

7.2.1.1 Model Description

AURORAxmp was used as the primary tool for conducting Vectren's risk assessment. AURORAxmp is an industrial standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a state of the art, mixed integer linear programing approach (MILP) to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets. It is widely used by electric utilities, consulting agencies, and other stakeholders to forecast generator performance and economics, develop Integrated Resource Plans (IRP), forecast power market prices, and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g. heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates as well as capital costs. The model is able to assess the potential performance and capital cost of existing and perspective generation technologies and resources, and make resource addition and retirement decisions for economic, system reliability, and policy compliance reasons on a utility system, regional or nationwide scale as needed. Outputs of the

model include plant generation, gross margin, emissions, and a variety of other metrics as needed.

Pace Global has used AURORA for well over 15 years as its primary model for asset valuation, power market forecast, and IRPs. The model is able to analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Pace Global has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic volatility in key market drivers and cross relationships between different market drivers. Pace Global has also developed modules to simulate the different operating characteristics of ISOs across the country. For this reason it is one of the most comprehensive, reliable and flexible tools in the market for conducting IRPs. Pace Global has successfully conducted numerous IRPs for many utilities across the country, it has gained wide acceptance before energy company managements, stakeholder groups and PUCs.

In order to perform the stochastic analysis, a set of probability distributions are required for key market driver variables. These include probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon), and capital costs.

7.2.1.1.1 Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones. Pace Global's long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook. This process is explained in detail in the Technical Appendix 10.5 Risk Appendix. Pace Global benchmarked the projections against MISO-

sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain.

7.2.1.1.2 Gas Stochastics

Pace Global developed natural gas stochastic distributions for Henry Hub and other basis points in MISO and elsewhere. These stochastic distributions are based on the base case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. To estimate future volatility, the volatility of the last 30 months is applied to 2016-2018, the volatility from 2011-2015 is applied to 2016-2025, and the volatility from 2005-2015 is applied to 2026-2035. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

7.2.1.1.3 Coal Stochastics

Pace Global developed coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins. These stochastic distributions are based on a base case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters. It should be noted that the majority of coal contracts in the U.S. are bilateral and only about 20 percent are traded on the NYMEX. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

7.2.1.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in the power dispatch modeling to capture the inherent risk associated with

regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on "expert-opinion"-based projections, as there are no historical data sets to estimate the parameters for developing carbon costs distributions.

7.2.1.1.5 Capital Cost Stochastics

Pace developed the uncertainty distributions for the cost of new entry units by technology types, which was used in the Aurora dispatch model for determining the economic new builds based on market signals. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a base case view of future all-in capital costs, historical costs and volatilities, and a sampling of results to develop probability bands around the base case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events.

7.2.1.1.6 Cross-Commodity Stochastics

Pace Global has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes, which is a separate stochastic process from those for gas, coal and CO_2. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Pace Global conducted fundamental analysis to define the relationship between gas-coal dispatch cost and demand. The dispatch cost of gas and coal was calculated from the fuel stochastics and CO_2 stochastics, along with generic assumptions for VOM. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

7.2.1.2 Results

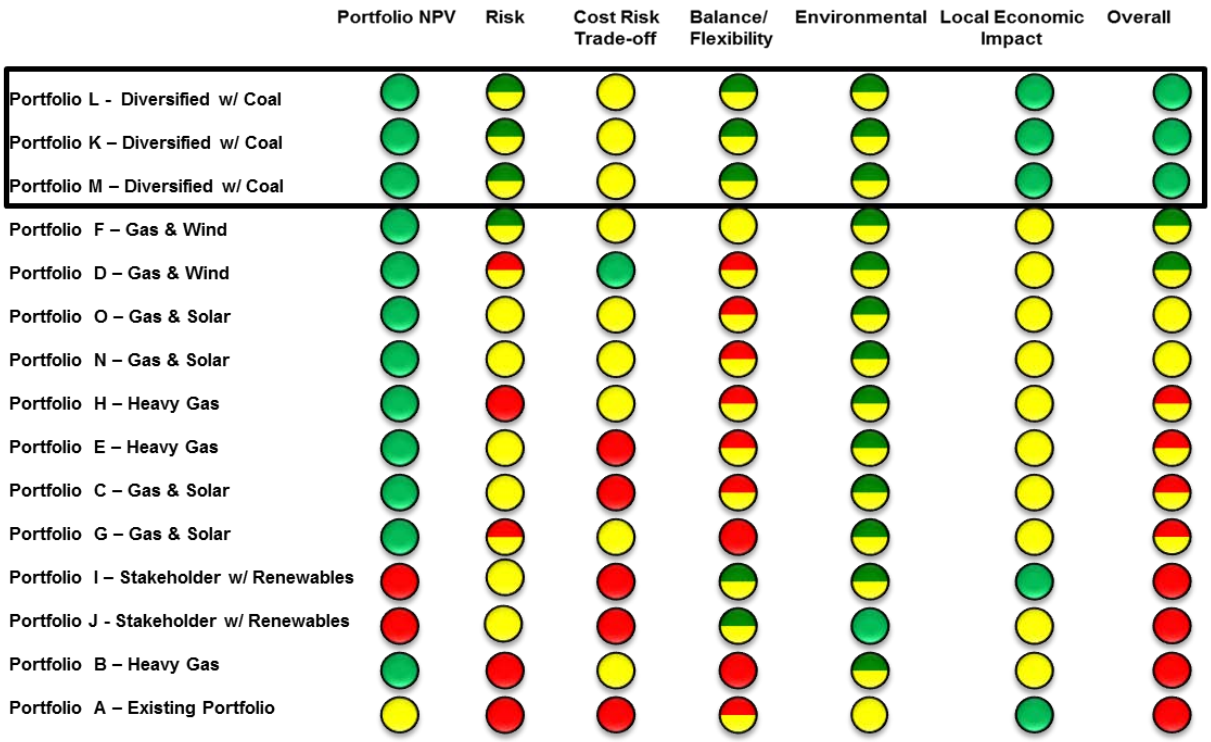
7.3 RISK ANALYSIS SUMMARY OF RESULTS

As summarized in an earlier section, Pace Global conducted a risk analysis on 15 portfolios. The analysis subjects each portfolio to 200 iterations (future market and regulatory outcomes). Then portfolios were ranked by each group of key criteria and associated metrics. The best performers in each metric were given a green color and the worst were given a red color; yellow was also shown as caution within a given metric.

Figure 7.16 summarizes the rankings for each metric. This figure shows that the diversified portfolios with coal resources performed better than the other portfolios across all of the metrics.

The recommended portfolio (Portfolio L) adopted renewables earlier than the other diversified portfolios with coal in them.

Figure 7.16 – IRP Portfolio Balanced Scorecard

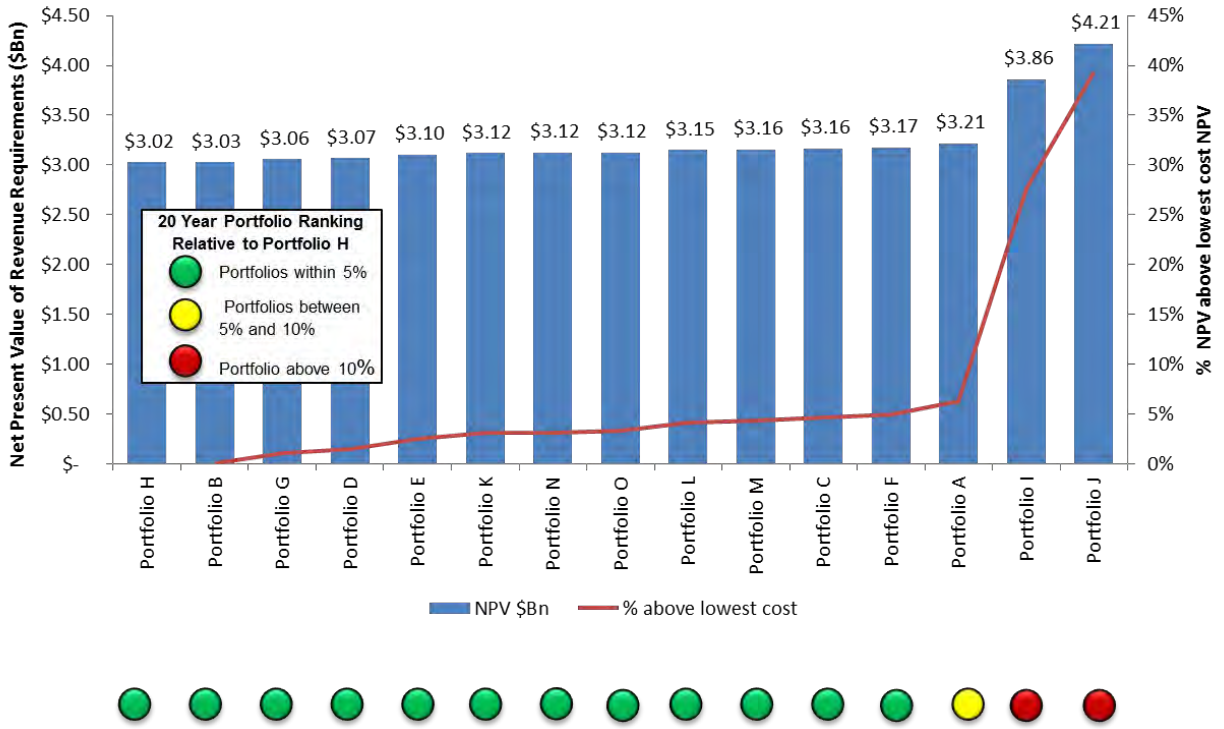


The sections below build up the metrics one at a time.

7.3.1 Customer Rates

The portfolio with the lowest mean or average costs across all 200 iterations will facilitate lower customer rates than other portfolios. The portfolios that were within 5% of the portfolio with the lowest expected cost (the net present value of revenue requirements) were given a green color, and the portfolios that were 10% or more expensive than the lowest cost portfolio were given a red color.

Figure 7.17 – IRP Modeling – 20-Year NPV Ranking



7.3.2 Risks

Four different risks were considered as part of the "Risk" metric.

One measure of risk is the volatility of the portfolio cost across the 200 iterations. The most commonly used measure of volatility is the standard deviation of the mean. The portfolios whose standard deviations of the mean were within 10% of the least volatile portfolio were given a green color. The portfolios that had standard deviations 15% or more than the lowest portfolio were given a red color. The recommended portfolio (Portfolio L) received a green color. Please see slide 50 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The second measure of risk is exposure to volatilities in the wholesale energy market prices. The portfolio with the lowest average purchases from the market is less subject to market price volatility. When looking at the range of market purchases, those with

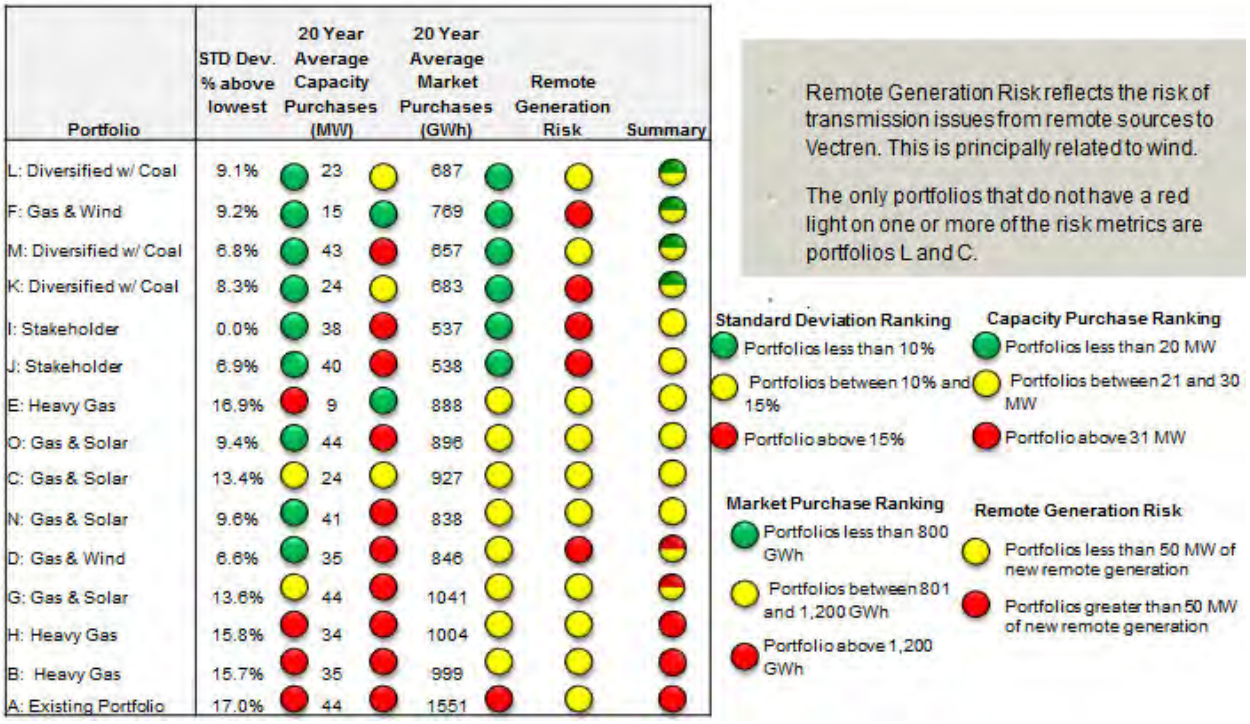
less than 800 GWhs per year on average were given a green color and those above 1,200 GWhs were given a red color. Again, Portfolio L received a green color rating. Please see slide 52 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The third measure assesses the potential exposure to MISO capacity markets. Although each portfolio is designed to meet MISO reserve margin targets under reference case conditions, they each may fall short if demand growth is higher than expected. The average number of additional capacity purchases across all 200 iterations was computed to see which needed the most incremental capacity purchases. Portfolios purchasing less than 20 MW per year on average received a green color and those above 35 MW per year received a red color. The recommended portfolio received a yellow color. Please see slide 51 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

The fourth and final risk measure was remote generation risk. Portfolios with generation assets located away from Vectren's service territory are exposed to greater risk of transmission congestion and outages. Portfolio L has limited susceptibility to remote generation risk.

The overall risk measure is the average of the four colors. All three of the diversified with coal portfolios (K, L, and M) were at the top of the group on the four risk measures.

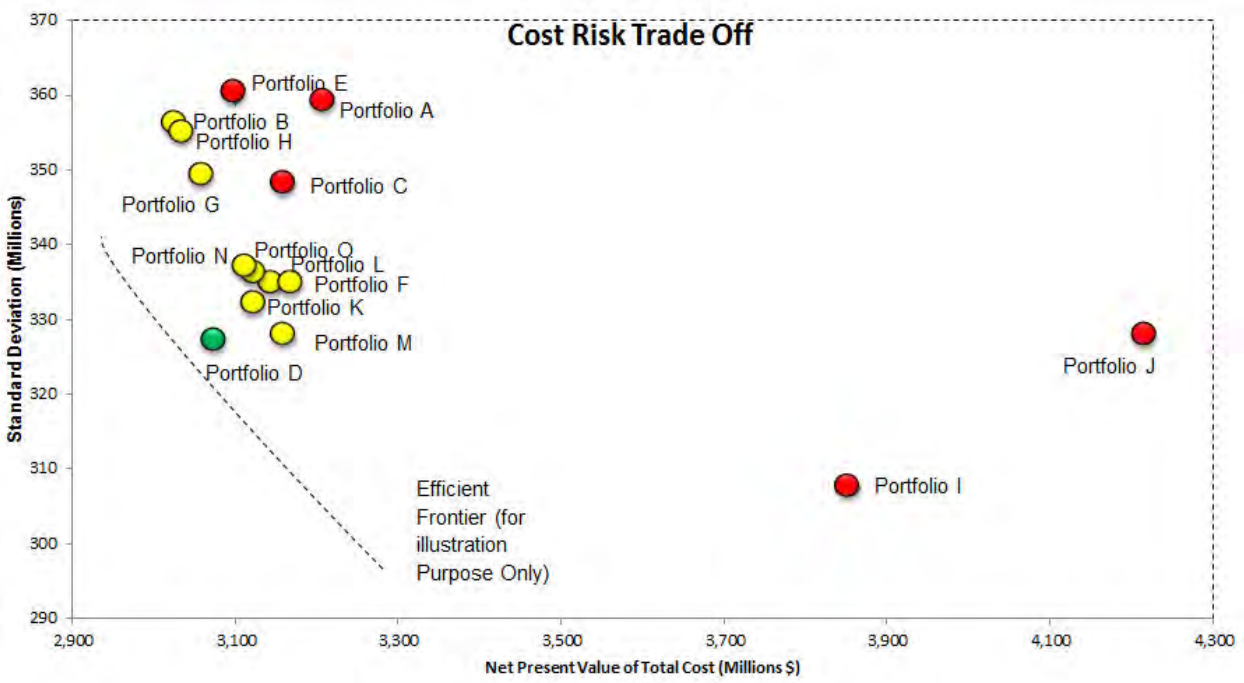
Figure 7.18 – Risk Metric Summary



7.3.3 Cost-Risk Tradeoff

Cost and Risk tradeoff relates two variables, expected costs and the standard deviation of cost, to provide a metric of whether a portfolio hedges risk in a cost effective manner. The following graph shows some portfolios have both higher expected costs and higher standard deviations than other portfolios (receiving a red color). Others, like the two stakeholder portfolios, have very high expected costs, so high that they far exceeded the benefit of these portfolios' lower standard deviation. The recommended portfolio (Portfolio L) was given a yellow color.

Figure 7.19 – Portfolio Standard Deviation Risk (vertical axis) vs. Expected Cost (horizontal axis) Tradeoff



7.3.4 Environmental Issues

All of the portfolios will easily meet the requirements of the Clean Power Plan. Nearly all portfolios are approximately 15% or more below the required level of carbon reductions. Portfolio L will reduce carbon levels by over 45%. Moreover, nearly all the portfolios will reduce both SO_2 and NO_X levels by over 80%. While the stakeholder portfolios have the greatest reductions, all other Portfolios received a yellow/green color. Please see slides 63-65 from the November 29th Public Stakeholder meeting found in Attachment 3.1 Stakeholder Materials for more information.

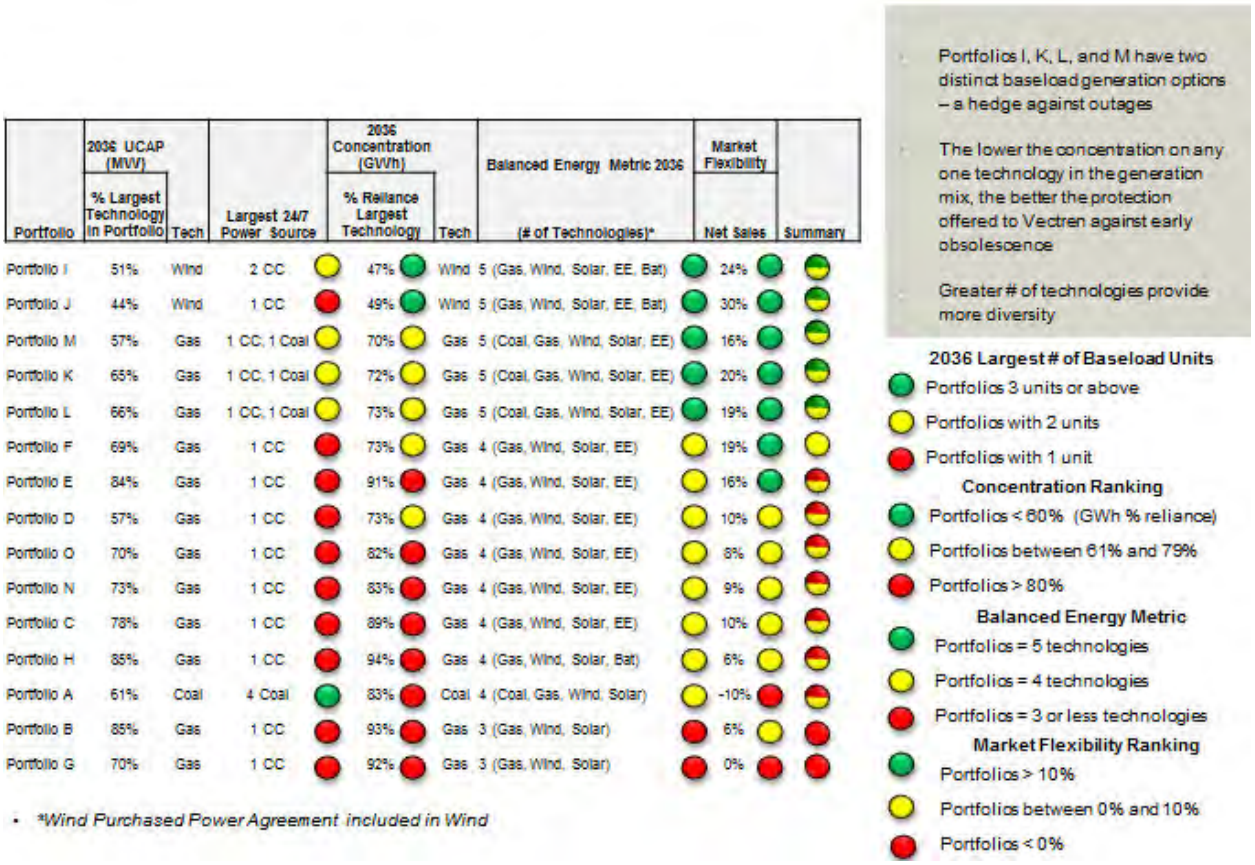
7.3.5 Balance and Flexibility

Balance and flexibility are important objectives to ensure that Vectren has a diverse generation mix that does not rely too heavily on the economics and viability of one technology or one site. In addition, portfolios with the greatest number of technologies

are ranked higher than those with fewer numbers. Finally portfolios with more net sales have the flexibility to adapt to unexpected breakthroughs in technology.

The recommended portfolio (Portfolio L) is among the best portfolios considering the number of technologies (five) relied upon. It also has one of the higher net sales levels.

Figure 7.20 – Balanced Energy Summary Metric



Portfolio	2036 UCAP (MW) % Largest Technology in Portfolio	Tech	Largest 24/7 Power Source	2036 Concentration (GWh) % Reliance Largest Technology	Tech	Balanced Energy Metric 2036 (# of Technologies)*	Market Flexibility Net Sales	Summary
Portfolio I	51%	Wind	2 CC	47%	Wind	5 (Gas, Wind, Solar, EE, Bat)	24%	
Portfolio J	44%	Wind	1 CC	49%	Wind	5 (Gas, Wind, Solar, EE, Bat)	30%	
Portfolio M	57%	Gas	1 CC, 1 Coal	70%	Gas	5 (Coal, Gas, Wind, Solar, EE)	16%	
Portfolio K	65%	Gas	1 CC, 1 Coal	72%	Gas	5 (Coal, Gas, Wind, Solar, EE)	20%	
Portfolio L	66%	Gas	1 CC, 1 Coal	73%	Gas	5 (Coal, Gas, Wind, Solar, EE)	19%	
Portfolio F	69%	Gas	1 CC	73%	Gas	4 (Gas, Wind, Solar, EE)	19%	
Portfolio E	84%	Gas	1 CC	91%	Gas	4 (Gas, Wind, Solar, EE)	16%	
Portfolio D	57%	Gas	1 CC	73%	Gas	4 (Gas, Wind, Solar, EE)	10%	
Portfolio O	70%	Gas	1 CC	82%	Gas	4 (Gas, Wind, Solar, EE)	8%	
Portfolio N	73%	Gas	1 CC	83%	Gas	4 (Gas, Wind, Solar, EE)	9%	
Portfolio C	78%	Gas	1 CC	89%	Gas	4 (Gas, Wind, Solar, EE)	10%	
Portfolio H	85%	Gas	1 CC	94%	Gas	4 (Gas, Wind, Solar, Bat)	6%	
Portfolio A	61%	Coal	4 Coal	83%	Coal	4 (Coal, Gas, Wind, Solar)	-10%	
Portfolio B	85%	Gas	1 CC	93%	Gas	3 (Gas, Wind, Solar)	6%	
Portfolio G	70%	Gas	1 CC	92%	Gas	3 (Gas, Wind, Solar)	0%	

- *Wind Purchased Power Agreement included in Wind

7.3.6 Local Economic Impact

The last metric is local economic impact to the community. This includes local output reductions and tax losses if local generation is closed. In addition, construction additions and operation of replacement generation was considered. Portfolio L has the lowest negative impact among portfolios. The full economic impact report can be found in Technical Appendix Attachment 7.4 Economic Impact Study – Economic Ripple Effects of Diversifying Power Generation Portfolio.

Figure 7.21 – Local Economic Impact



Closing FB Culley 3 by 2024 would have an adverse economic impact to the community, particularly hard hit Warrick County*

- Total 1-year Output Impact = $145 million
- Total 1-year State and Local Tax Impact = $7 million, of which Vectren's property taxes from Culley 3 alone currently contribute approximately $350 thousand dollars annually to Warrick County School Corp.
- Total Jobs Impact = 271, which includes 82 direct job losses at the plant

Building and operating a combined cycle gas plant within Vectren's service territory would minimize the economic impact to the community of closing the AB Brown Plant by 2024

- Total Output Impact of construction = $950 million
- Total Output Impact of operating the plant = $50 million per year

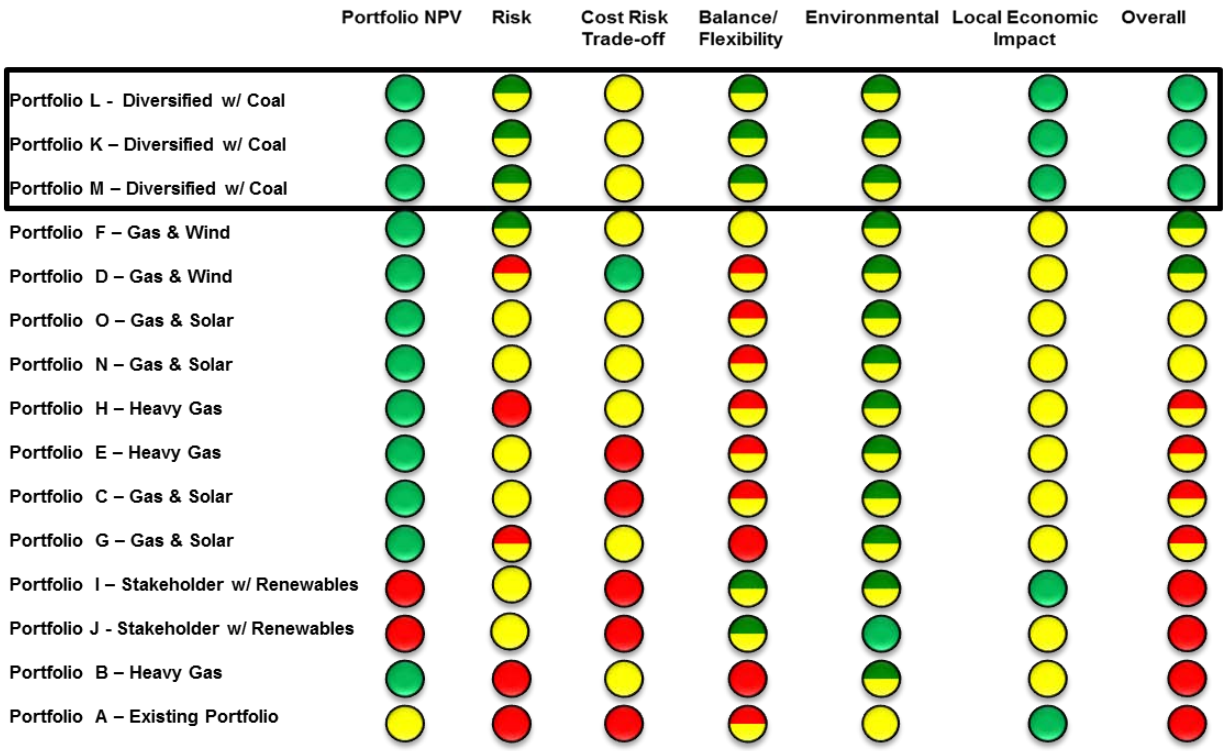
*Alcoa closed its smelter operation in the spring of 2016. The impact is compounded by FB Culley 2 by 2024. Economic impact study conducted by professors of economics and finance at the University of Evansville. Total economic impact based on an Economic Impact Study using IMPLAN social accounting system. Total impact includes direct, indirect, and induced effects.

SECTION 8
IRP RESULTS AND RECOMMENDATION

8.1 SCORECARD COMPARISON

Balanced portfolios L, K, and M, the Diversified with Coal Portfolios, perform best across all metrics, as shown below in Figure 8.1. Of the three diversified portfolios, Portfolio L has early renewables and low cost, highly efficient peaking capacity to back up variable renewable resources, mitigate capacity market risk, and allow for economic development opportunities.

Figure 8.1 – IRP Portfolio Balanced Scorecard



8.2 PREFERRED PORTFOLIO RECOMMENDATION

The preferred portfolio L provides a number of benefits to Vectren customers and other stakeholders:

- Is among the best performing portfolios across multiple measures on the balanced scorecard
- Is among the lower cost portfolios (within 4% of the lowest cost portfolio)

- Leads to a lower carbon future – Achieves almost 50 percent reduction in carbon (base year 2012) by 2024, which exceeds the Clean Power Plan (CPP) requirements – carbon emissions reduction from 2005 levels would be almost 60 percent
- Brings renewables into the portfolio by 2019. Renewables and ongoing Energy Efficiency account for approximately 20% of total capacity by 2036
- Provides low-cost peaking generation through duct-firing that enhances opportunities for economic development and wholesale sales, which lowers customer bills
- Avoids reliance on a single fuel and provides a balanced mix of coal, gas, and renewables. While reliance on gas is significant, a duct-fired plant would allow for back up of further variable renewable resources in the long term
- Is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. University of Evansville professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately 7 million dollars annually. Moreover, to the extent a new gas unit is built at the AB Brown site, over 100 total jobs are expected to be retained in the community. Total state and local tax impact would be approximately 4 million dollars annually.
- Reduces dependence on coal-fired generation over time and provides flexibility to adapt to changes in technology
- Takes advantage of tax incentives for solar power plants

8.2.1 Description of the Portfolio

8.2.1.1 Retirements

Vectren will be replacing a large portion of its aging generating fleet under the preferred plan. The preferred portfolio retires a significant amount of coal generation, including: Brown Units 1 & 2 and FB Culley Unit 2. While the Brown units are newer than FB

Culley 3, they have more expensive scrubber technology used to scrub SO_2 from the air. Vectren invested early in this clean coal technology on Brown units 1 and 2 in 1979 and 1986, respectively. The AB Brown SO_2 scrubbers are of a design known as dual alkali scrubbers. The FB Culley forced oxidation SO_2 scrubber was retrofitted years later and has better SO_2 removal efficiency with significantly lower operating costs when compared to the AB Brown dual alkali scrubbers. It should be noted that the boiler and turbine generator actually represent only a portion of the equipment required for a modern environmentally compliant coal plant. Successful coal unit operation relies heavily on extensive pollution control equipment. In short, environmental compliance is projected to be less expensive at Culley than Brown.

Additionally, the preferred plan has additional benefits in regard to having generation located on both sides of the Evansville load. If all generation were retired on one side of the system, voltage regulation issues would arise on the side of the system that was without generation. Should the combined cycle plant be built on the west side of the system, Culley 3 can help provide this support for the east side of the system.

The preferred portfolio also retires several small, inefficient gas peaking units due to age, including: Broadway Avenue Gas Generating Station 1 (BAGS 1) in 2019, Northeast 1 & 2 gas peaking units in 2019, and BAGS 2 in 2025. The preferred plan calls for the new combined cycle gas turbine to be duct-fired, which will replace older, inefficient peaking capacity with much more efficient peaking capability. Depending on set up, duct-firing can provide approximately 200 MWs (Installed Capacity) of efficient peaking capacity capability through gas burners located within the heat recovery steam generator. These burners can be fired to generate more power during times of high demand. This technology is about half of the cost of a comparable simple cycle gas turbine.

8.2.1.2 Existing

The preferred portfolio continues use of FB Culley 3, which is Vectren's most efficient coal unit. This 270 MW unit is controlled for NO_X with an SCR. It is controlled for SO_2 with an FGD. Additionally, it has a fabric filter to remove particulate matter and is controlled for mercury and SO_3. It should also be noted that the FB Culley SO_2 FGD is a different design than the FGDs on the AB Brown coal units. The FB Culley FGD achieves more efficient SO_2 removal at significantly lower operating costs than the FGD at AB Brown. Further, most of the FGD byproduct at FB Culley is beneficially reused in the manufacture of drywall, which also reduces costs when compared to landfilling the AB Brown FGD byproduct. Vectren studies say that the going forward environmental compliance costs at FB Culley are expected to be lower than at AB Brown. And lastly, maintaining generating facilities on both sides of Evansville is desirable from a reliability and voltage regulation perspective.

8.2.1.3 Renewables

Solar photovoltaic (PV) technology is key to providing future, clean energy as part of a balanced, economical portfolio. However, PV is relatively new as a source of utility-scale generation. Each potential project poses unique challenges including site-selection and land-use competition, the amount of solar irradiance available for conversion to electricity, transmission and interconnection design, and component-level configuration of the plant. Due to the complexity of these projects, energy companies take an incremental approach to solar plant development, gaining proficiencies in these resource options along the way and unlocking the greatest value from future renewable energy installations for the communities in which they serve.

Vectren plans to explore a variety of solar PV arrangements while providing universal solar power for its customers from installations in rural as well as rooftop settings. The preferred portfolio calls for a 4 MW solar plant by 2018. This is representative of several, smaller, energy company-owned and operated projects that are expected to be in place by this time, including a 2 MW solar power plant with a 1 MWh battery storage

system. Additionally, Vectren is in talks with the City of Evansville on joint projects to be finalized in the first quarter 2017, and Vectren is in on-going discussions to develop other potential projects.

Vectren's plans to integrate up to 54 MWs of solar power before tax incentives expire in 2020. The solar projects are designed to afford Vectren South and its customers an opportunity to make a meaningful step to integrating solar power into Vectren South's integrated resource portfolio. Vectren plans 50 MW of solar in 2019, which corresponds with clean energy tax incentives. Projects meeting the ITC Requirements by December 31, 2019 are eligible for 30% tax credit, helping to offset comparatively higher cost of solar generation to other resources. Timing of this plant may change should these incentives not be available. After 2020, the sustained growth rate of solar power penetration is uncertain due to policy, technological, economic, and a variety of other factors. However, in the recent release of its 2016 Standard Scenarios Report, the National Renewable Energy Laboratory cited solar PV, especially universal solar power plants, as a growing contributor of renewable energy generation. Vectren's preferred portfolio positions the company to efficiently adapt to the evolving energy mix while passing the benefits of current tax incentives on to its customers.

8.2.1.4 Energy Efficiency

The preferred portfolio continues energy efficiency programs throughout the next 20 years to help cost effectively serve Vectren customers, providing them with tools to help manage their energy bills. The preferred portfolio includes energy efficiency equivalent to 1% of eligible sales annually for years 2018 through 2020. Vectren will file its 2018-2020 energy efficiency plan in the spring of 2017, which is consistent with this level.

Vectren ran several scenarios with varying future states. Three of the seven model runs selected 1% energy efficiency throughout the 20-year period, and one selected 2% energy efficiency over this time period. These alternate scenario runs helped to inform the preferred level of energy efficiency; however, judgment for reasonableness is still

necessary. Vectren included energy efficiency resources in the preferred plan that is viable and can confidently be achieved over the 20 year period (0.75% of eligible sales between 2021-2026 and 0.50% thereafter to cover incremental expected energy and demand growth). The level of energy efficiency selected in the next IRP will inform the 2021-2023 DSM filing.

8.2.2 Environmental Benefits

Vectren has reduced carbon emissions by 31% between 2005 and 2015. The preferred portfolio leads to a lower carbon future by reducing CO_2 by 46% from 2012 levels, which exceeds the Clean Power Plan requirements. Additionally, the preferred portfolio is expected to reduce SO_2 and NO_X by over 80% compared to the average of 2012-2015 levels.

A new CCGT will yield a significant reduction in air, water, and waste emissions for Vectren's generation portfolio. The ability for rapid ramp-up will allow effective back up power to renewable generation sources such as the new proposed solar projects. Additionally, a new CCGT is more efficient (requires less fuel per kilowatt hour) than a coal unit.

The preferred portfolio keeps FB Culley 3, which is controlled for multiple air pollutants. This 270 MW unit is controlled for NO_X with an SCR. It is controlled for SO_2 with an FGD. Additionally, it has a fabric filter to remove particulate matter and is controlled for mercury and SO_3. The unit has dry fly ash handling which allows for the recycling of the fly ash at a cement kiln in addition to the synthetic gypsum (FGD solids) which goes to a wallboard manufacturer.

8.2.3 Reliability

Each of the portfolios were required to meet all of the planning (PRM) and operational (UCAP) requirements set out by the Regional Transmission Operator (MISO) under each of the screening analyses. In the case of renewable builds, the ability of Vectren

to support variable resources limited the total capacity of renewables built into any one portfolio in the near term.

In addition, too much reliance on one site or on one technology or fuel source, or too much reliance on remote sources, can expose Vectren to the risk of weather, transmission, or other risks that can at least temporarily impact reliability. These factors were carefully considered in the Energy Balance metric. The recommended Portfolio L meets all of the MISO reserve requirements, had five technologies in the capacity mix, two 24/7 baseload technologies, and no additional remote sources (beyond its existing contracts), which provides a relatively secure, reliable portfolio.

8.2.4 Cost

Expected costs over the planning horizon are one of the most important metrics that were evaluated in the risk analysis. Over 200 different scenarios (future conditions) were evaluated to fully test each of the 15 portfolios. While the selection of a combined cycle plant with duct-firing was consistently selected as part of the most economic portfolios, the majority of the 15 portfolios evaluated were within 5% of the lowest cost portfolio. The lowest cost scenarios were “heavy gas” portfolios which provided less diversity and less flexibility than the other portfolios. The recommended Portfolio L exhibited costs 4.1% higher than the lowest portfolio. Compared to this, the highest cost portfolios were the Stakeholder Portfolios, which were both over 25% higher cost than the lowest cost portfolios.

8.2.5 Benefits of a Balanced Energy Mix

In a world where the rate of technological advance is creating greater and greater levels of uncertainty, the benefits of a balanced energy mix cannot be understated. Five years ago, few predicted that the shale boom would result in low and relatively stable gas prices for the past five years. While renewable costs continue to decline, it is impossible to predict when battery storage technologies will become economic or whether it will fundamentally change the economics of base load generation. The best

way to plan in this environment is to provide a diverse portfolio, which provides natural hedges against unforeseen changes in regulations, technologies and markets. Placing too large a bet on one and only one technology with no flexibility to adapt would leave Vectren subject to unexpected changes that could result in significant stranded assets.

The recommended Portfolio L takes a balanced approach towards capturing the current promises of combined cycle plant afforded by the mainstream low gas price outlook, and retaining a hedge against new gas capital investment becoming stranded later in the relatively unlikely event of dramatic storage technology breakthrough or unexpected severe gas extraction regulation, which is diminished by retaining a modest amount of existing coal. Portfolio L further reduces exposure to the risk of relying heavily on any single technology by incorporating three additional sources of energy generation, from solar, wind, and through energy efficiency measures.

8.2.6 Flexibility

Flexibility is another important objective for Vectren's future portfolio. Prior to the 2016 presidential election, greater regulations on natural gas, tighter carbon controls, and more regulations were commonly expected. With President-Elect Trump's election, even the current regulations on the Clean Power Plan could be in jeopardy. It is clear that with the new administration, and the rate of technological advance, Vectren must position itself to be as flexible as possible. With that in mind, Vectren needs to be able to react quickly should such factors as renewable tax provisions and the regulations on coal call for changes to its portfolio composition, such as by closing its coal plants or accelerating/delaying adding renewable generation. Whether Vectren has the agility to react in a timely manner depends in part on whether Vectren's portfolio has sufficient reserve capacity to avoid excessive exposure to market volatility during the transition, when some established market hedges (plants) retire, and before new ones (plant builds) can be completed. This reserve capacity is reflected in the amount of economic generation a portfolio has available for export into the wholesale market under normal circumstances.

8.2.7 Transmission/Distribution

An assessment of Vectren's transmission system was conducted to ensure that the preferred portfolio would support continued system reliability. The analysis indicated that the system would perform well; however, certain transmission enhancements will be required to support continued reliability. A new west to east 138 kV line from the AB Brown power plant to Pigeon Creek substation to the Culley power plant will need to be constructed. Also, additional dynamic reactive power support is needed in the eastern part of system, which will require a synchronous condenser, Static Var Compensator (SVC), or an alternative reactive power source.

8.2.8 Risk

A number of risks were considered in selecting the recommended portfolio. The first risk measured was the stability of the portfolio over the 200 scenarios run. The "standard deviation" measures the variability of portfolio cost around the mean value, with a lower standard deviation representing a relatively stable portfolio considering uncertainties in load, fuel prices, capital costs, and emissions. Another risk is exposure to the market. Owned generation is a hedge against market price fluctuations, so lower market purchases reduce Vectren's exposure to market fluctuations. A third risk is tied to incremental capacity purchases that would be required to meet on-going UCAP reserve requirements. These incremental purchases are not explicitly captured in the risk metrics. The fourth metric is the risk of remote sources, which subjects capacity to greater levels of transmission and site related risks, simply by being remote to its service territory.

The recommended Portfolio L belongs to the low-to-mid group of portfolios in terms of cost standard deviation, which indicates its expected costs are relatively stable over a wide range of market conditions. It requires some of the lowest levels of energy market purchases among the portfolios examined, which further reduces Vectren's exposure to market heat rate risk. While Portfolio L has some transmission congestion risk resulting from reliance on existing remote wind contracts, it controls this risk by calling for no

further wind generation. Only in potential requirements for further capacity purchases does Portfolio L fall to the middle tier amongst all portfolios examined. But when examined together, Portfolio L is one of the best among the portfolios examined.

8.2.9 Economic Impact Analysis Results

The preferred portfolio is among the best portfolios in terms of limiting negative economic impact from job loss and local tax base. University of Evansville professors concluded that the economic ripple effect of losing 82 FB Culley jobs equates to 189 additional job losses in the community. Total state and local tax impact would be approximately seven million dollars annually. Currently, taxes from FB Culley 3 alone contribute approximately $350 thousand annually to the Warrick County School Corp. The total output impact of FB Culley 3 is $145 million annually.

Additionally, building and operating a combined cycle gas plant within Vectren's service territory would minimize the economic impact to the community of closing the AB Brown Plant by 2024. The construction of the plant is expected to produce $950 million in total economic output. Once operational, the plant is expected to have total output of $50 million annually.

8.2.10 Fuel Inventory and Procurement Planning

It is impossible to predict price fluctuations in commodity prices such as coal and natural gas. Vectren uses coal contract strategies intended to even out short term price fluctuations, such as locking in prices for various overlapping time horizons. Normally these contract renewals are staggered in time in order to even out short term price fluctuations. Coal suppliers and transportation providers generally require firm commitments in regard to quantities; however, Vectren coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently Vectren utilizes non-firm pipeline delivery and gas storage for the existing peaking units. It is planned that the future combined cycle gas fired 24x7 generator will utilize firm pipeline supply contracts.

SECTION 9
SHORT TERM ACTION PLAN

9.1 DIFFERENCES BETWEEN THE LAST SHORT TERM ACTION PLAN FROM WHAT TRANSPIRED

Consistent with its commitment in the 2014 Short Term Action Plan, Vectren has continued monitoring changes in inputs to its integrated resource planning. The 2016 IRP accounts for changes that have occurred and, as a result, changes the recommended short-term action plan.

The 2014 IRP called for no additional supply side resources to meet customer needs based on reasonable assumptions made in that IRP. Accordingly, Vectren did not pursue any new supply side resources in 2014 or 2015.

The 2014 IRP did support continued energy efficiency programs designed to save 1% of eligible retail sales. Vectren proposed the 2016-2017 Electric DSM Plan to obtain approval of programs to achieve this level of savings. The Commission approved this plan on March 23, 2016 in Cause No. 44645. Consistent with the 2014 IRP, the framework for the 2016-2017 filed plan was modeled at a savings level of 1% of retail sales adjusted for an opt-out rate of 80% eligible load.

Since 2014 gas prices have dropped and are projected to remain low and stable over the long term. Shale gas has revolutionized the industry, driving these low gas prices, and is fueling a surge in low-cost gas generation around the country. Projected gas prices were a major driver in this analysis.

Vectren's planning efforts for the 2016 IRP identified changes from the 2014 assumptions that drive different conclusions. In the ensuing two years, environmental rules (the CPP, ELG, and CCR) were finalized. The final ELG and CCR were more stringent than originally proposed by the EPA. The stricter standards impacted the cost of continuing to rely on our coal fired power plants in our 2016 IRP analysis.

Change impacting Vectren's modeling also resulted from actions of industrial operations in its service territory. In January of this year, Alcoa announced it would permanently cease production of its Warrick Operation smelter in the 1st quarter. Alcoa also communicated that the on-site rolling mill and power plant will continue to operate. Of Alcoa's generating units, Warrick 4 is jointly owned by Alcoa and Vectren. Alcoa is in the midst of operational and organizational changes. It is uncertain whether Alcoa will continue to run the jointly owned Warrick 4 electric generating unit. Vectren will continue talks with Alcoa as to the best course of action for Warrick 4. Also, one of Vectren's large customers brought on-line a large cogeneration facility that impacted Vectren's load forecast.

Other changes arose from efforts to continue to refine the IRP process. Vectren developed a more robust risk modeling approach for the 2016 IRP. Studies of potential customer-owned combined heat and power generation facilities were analyzed.

9.2 DISCUSSION OF PLANS FOR NEXT 3 YEARS

9.2.1 DSM

Vectren will seek Commission-approval for its 2018-2020 electric demand side management (DSM) plan in 2017. The 2018-2020 energy efficiency savings will be guided by the 2016 IRP process. Once approved by the Commission, the Vectren Oversight Board, including the Office of Consumers Counselor (OUCC), Citizens Action Coalition (CAC), and Vectren, will oversee the implementation of energy efficiency programs.

9.2.2 Solar Projects

Vectren will seek Commission approval to own and construct 4-6 MWs of energy company owned solar projects in its service territory, including:

- 2 MW universal solar power plant with a 1 MWh battery storage system

- a project to develop a solar power plant with the City of Evansville, details of which are expected to be finalized in the first quarter 2017, and
- other potential project discussions (on-going).

Additionally, Vectren plans to file and seek approval for 50 MW of solar. The timing of this project was advanced to enable Vectren to reap benefits of clean energy tax incentives for its customers. Timing of this solar power plant may change based on the availability of these incentives.

9.2.3 Environmental Permits for ELG/CCR

Vectren has timely NPDES permit renewals pending for Brown and Culley. As part of this permit renewal process Vectren will establish a compliance schedule for constructing new water pollution control equipment at FB Culley and list retirement dates for units that will not be upgraded. Vectren will seek Commission-approval to recover costs associated with the new pollution control equipment at FB Culley.

9.2.4 Generation Transition

In early 2017 Vectren will continue to evaluate several options as it pertains to building a new CCGT; building a CCGT at the AB Brown site (currently modeled in this IRP) or partnering with another energy company on a large CCGT build. While Vectren feels that the AB Brown site is attractive to maintain reliable, on-system generation (good water supply, access to 345kv electric transmission line, limits economic impact to the community, etc.), additional analysis is needed to ensure that that Vectren is pursuing the best option for customers.

Vectren will use the coming months to develop a generation transition case, complete with timelines and costs, which will be filed with the Commission for approval. The filing is expected to seek a Certificate of Public Convenience and Necessity (CPCN) to construct a new, fully fired combined cycle gas unit.

As Vectren works to replace much of its existing coal fleet with a new Combined Cycle Gas Turbine, Vectren will enter MISO's Generator Interconnection Queue process. During this process, MISO studies the impacts of new generation on the MISO transmission system and identifies any needed transmission facility upgrades. The process takes approximately 18 months and upon completion of satisfying any identified upgrades, Vectren will obtain a signed Generator Interconnection Agreement that will allow the new Combined Cycle Gas Turbine to connect to MISO's transmission system and participate in the MISO energy markets.

9.2.5 Ability to Finance the Preferred Portfolio

The Company has access to a $350 million revolving credit facility through its parent company Vectren Utility Holdings, Inc. ("VUHI"), internal cash flows, and transfers of cash flow from nonutility businesses. Additionally, Vectren and its subsidiary companies have strong investment grade ratings from both Moody's and Standard and Poor's, which affords access to the capital markets at attractive rates. This flexibility and ample access to funds will allow for the funds to be obtained in a manner consistent with the timing of the capital expenditures.

SECTION 10
TECHNICAL APPENDIX

10.1 CUSTOMER POWER NEEDS APPENDIX

10.1.1 Forecast Inputs

10.1.1.1 Energy Data

Historical Vectren sales and revenues data were obtained through an internal database. The internal database contains detailed customer information including rate, service, North American Industrial Classification System (NAICS) codes (if applicable), usage, and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

10.1.1.2 Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana, and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS), and industrial (large) sales.

10.1.1.3 Weather Data

The daily maximum and minimum temperatures for Evansville, IN were obtained from DTN, a provider of National Oceanic and Atmospheric Administration (NOAA) data. NOAA data is used to calculate monthly heating degree days (HDD) and cooling degree days (CDD). HDDs are defined as the number of degrees below the base temperature of 65 degrees Fahrenheit for a given day. CDDs are defined as the number of degrees above the base temperature of 65 degrees Fahrenheit for a given day. HDDs and CDDs are averaged on a monthly basis. Normal degree days, as obtained from NOAA,

are based on a thirty year period. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

10.1.1.4 Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. Note that in 2013 an appliance survey of Vectren's residential customers was conducted to compare its territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of Vectren's actual territory.

10.1.2 Appliance Saturation Survey and Continuous Improvement

Vectren surveys residential customers as needed. A residential appliance saturation survey was conducted in the summer of 2013. The survey was completed by a representative sample of customers. Results from this survey were used to reflect market shares of actual residential customers. The residential average use model statistics were improved by calibrating East South Central Census regional statistics with the appliance saturation of Vectren's customers. Note that Vectren's service area is technically in the southern most point of the East North Central Census region, bordering the Ease South Central region. Model results were improved by calibrating to the East South Central region.

At this time, Vectren does not conduct routine appliance saturation studies of GS and large customers. These customers are surveyed when needed for special programs. However, Vectren's large and GS marketing representatives maintain close contact with its largest customers. This allows Vectren to stay abreast of pending changes in demand and consumption of this customer group.

Vectren continually works to improve the load forecasting process in a variety of ways. First, Vectren is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Vectren forecasters attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. Vectren forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, Vectren discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. Vectren compares and contrasts Vectren model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

10.1.3 Overview of Past Forecasts

The following tables outline the performance of Vectren's energy and demand forecasts over the last several IRPs by comparing Weather Normalized (WN) sales and demand figurers to IRP forecasts from 2006-2014.

Weather-normalization is performed each month by importing customer count, meter read schedule, billing month sales, and daily temperature into Vectren's Electric AUPC Estimation system. Underlying the Electric AUPC Estimation System is a set of MetrixND (Itron's statistical modeling software) average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data, and daily system delivery data. On execution, the Use per Customer (UPC) project files read actual weather data from the Access weather database and generate daily use per customer estimates for the revenue classes. The results are exported back to the AUPC system database where the predicted daily use estimates are used to allocate billed monthly sales to the calendar-month period. The models are also executed using

normal daily temperatures. Results are written back to the AUPC system database. Weather-normalized sales are then exported from the Electric AUPC Estimation system.

The following tables show the WN[49] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

Figure 10.1 – Total Peak Demand Requirements (MW) , Including Losses and Street Lighting

Year	2005 Total Demand Forecast (MW)	2007 Total Demand Forecast (MW)	2009 Total Demand Forecast (MW)	2011 Total Demand Forecast (MW)	2014 Total Demand Forecast (MW)	WN 2016 Total Demand (MW)[50]	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,326					1,325	-0.1%				
2007	1,268					1,341	5.4%				
2008	1,237	1,184				1,166	-6.1%	-1.5%			
2009	1,257	1,216				1,066	-17.9%	-14.1%			
2010	1,275	1,237	1,153			1,154	-10.5%	-7.2%	0.1%		
2011	1,294	1,252	1,179			1,132	-14.3%	-10.6%	-4.2%		
2012	1,314	1,258	1,118	1,156		1,158	-13.5%	-8.6%	3.5%	0.2%	
2013	1,333	1,265	1,115	1,156		1,144	-16.5%	-10.5%	2.6%	-1.0%	
2014	1,350	1,272	1,107	1,165		1,133	-19.2%	-12.3%	2.3%	-2.8%	
2015	1,366	1,281	1,100	1,164	1,155	1,134	-20.5%	-13.0%	3.0%	-2.6%	-1.8%
Mean Absolute Error							12.4%	9.7%	2.6%	1.7%	1.8%

[49] 2009-2014 forecastd incorporates DSM into the class level forecasts and does not include wholesale energy. Note that large sales are not significantly influenced by weather and are therefore not weather normalized. The 2005-2007 Forecasts were before the Great Recession and do not include a significant amount of DSM.
[50] 2006-2009 peak not weather normalized

Figure 10.2 – Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2005 Total Energy IRP Forecast (GWh)	2007 Total Energy IRP Forecast (GWh)	2009 Total Energy IRP Forecast (GWh)	2011 Total Energy IRP Forecast (GWh)	2014 Total Energy IRP Forecast (GWh)	WN Total Energy Results (GWh)[51]	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	5,875					5,772	-1.8%				
2007	6,393					5,763	-10.9%				
2008	6,531	5,846				5,568	-17.3%	-5.0%			
2009	6,640	6,090				5,387	-23.3%	-13.0%			
2010	6,743	6,230	5,306			5,739	-17.5%	-8.6%	7.5%		
2011	6,846	6,329	5,460			5,857	-16.9%	-8.1%	6.8%		
2012	6,955	6,369	5,456	5,837		5,691	-22.2%	-11.9%	4.1%	-2.6%	
2013	7,060	6,422	5,434	5,807		5,768	-22.4%	-11.3%	5.8%	-0.7%	
2014	7,159	6,476	5,403	5,803		5,867	-22.0%	-10.4%	7.9%	1.1%	
2015	7,252	6,527	5,365	5,772	5,914	5,794	-25.2%	-12.6%	7.4%	0.4%	-2.1%
Mean Absolute Error							17.9%	10.1%	6.6%	1.2%	2.1%

Figure 10.3 – Residential Energy (GWh)

Year	2005 Res. IRP Forecast (GWh)	2007 Res. IRP Forecast (GWh)	2009 Res. IRP Forecast (GWh)	2011 Res. IRP Forecast (GWh)	2014 Res. IRP Forecast (GWh)	WN Res. Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,584					1,554	-1.9%				
2007	1,609					1,550	-3.8%				
2008	1,633	1,581				1,520	-7.5%	-4.0%			
2009	1,660	1,595				1,520	-9.2%	-4.9%			
2010	1,687	1,620	1,467			1,483	-13.8%	-9.2%	1.1%		
2011	1,716	1,645	1,440			1,483	-15.7%	-10.9%	2.9%		
2012	1,745	1,663	1,421	1,462		1,411	-23.7%	-17.9%	-0.7%	-3.6%	
2013	1,774	1,683	1,391	1,419		1,429	-24.1%	-17.7%	2.7%	0.7%	
2014	1,801	1,703	1,365	1,399		1,439	-25.2%	-18.3%	5.1%	2.8%	
2015	1,830	1,722	1,332	1,371	1,404	1,444	-26.7%	-19.2%	7.8%	5.0%	2.8%
Mean Absolute Error							15.1%	12.8%	3.4%	3.0%	2.8%

[51] Assumes 5.2% losses

Figure 10.4 – Commercial (GS) Energy (GWh)

Year	2005 Comm. (GS) IRP Forecast (GWh)	2007 Comm. (GS) IRP Forecast (GWh)	2009 Comm. (GS) IRP Forecast (GWh)	2011 Comm. (GS) IRP Forecast (GWh)	2014 Comm. (GS) IRP Forecast (GWh)	WN Comm. (GS) Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	1,566					1,342	-16.7%				
2007	1,594					1,371	-16.3%				
2008	1,625	1,380				1,346	-20.7%	-2.5%			
2009	1,660	1,384				1,324	-25.4%	-4.6%			
2010	1,694	1,404	1,275			1,321	-28.3%	-6.3%	3.4%		
2011	1,727	1,426	1,284			1,318	-31.0%	-8.2%	2.6%		
2012	1,764	1,438	1,296	1,375		1,266	-39.3%	-13.6%	-2.3%	-8.6%	
2013	1,800	1,455	1,304	1,383		1,298	-38.7%	-12.1%	-0.4%	-6.6%	
2014	1,834	1,472	1,307	1,399		1,312	-39.8%	-12.2%	0.4%	-6.6%	
2015	1,863	1,490	1,306	1,402	1,304	1,321	-41.1%	-12.8%	1.1%	-6.2%	1.3%
Mean Absolute Error							29.7%	9.0%	1.7%	7.0%	1.3%

Figure 10.5 – Industrial (Large) Energy (GWh)

Year	2005 Ind. (Large) IRP Forecast (GWh)	2007 Ind. (Large) IRP Forecast (GWh)	2009 Ind. (Large) IRP Forecast (GWh)	2011 Ind. (Large) IRP Forecast (GWh)	2014 Ind. (Large) IRP Forecast (GWh)	WN Ind. (Large) Results (GWh)	2005 % Diff.	2007 % Diff.	2009 % Diff.	2011 % Diff.	2014 % Diff.
2006	2,379					2,570	7.4%				
2007	2,422					2,538	4.6%				
2008	2,461	2,591				2,409	-2.2%	-7.5%			
2009	2,498	2,820				2,259	-10.6%	-24.9%			
2010	2,530	2,921	2,281			2,630	3.8%	-11.0%	13.3%		
2011	2,561	2,980	2,445			2,745	6.7%	-8.6%	10.9%		
2012	2,594	2,999	2,449	2,687		2,711	4.3%	-10.6%	9.7%	0.9%	
2013	2,624	3,014	2,449	2,693		2,735	4.1%	-10.2%	10.4%	1.5%	
2014	2,650	3,028	2,446	2,693		2,805	5.5%	-8.0%	12.8%	4.0%	
2015	2,674	3,040	2,445	2,688	2,916	2,722	1.7%	-11.7%	10.1%	1.2%	-7.1%
Mean Absolute Error							5.1%	11.6%	11.2%	1.9%	7.1%

Figure 10.6 – Historic Energy and Demand

	Res.	Comm. (GS) Sales	Ind. (Large)	Other	Total Energy[52]	Total Demand[53]
2006	1,469	1,321	2,570	20	5,660	1,165
2007	1,631	1,412	2,538	19	5,892	1,182
2008	1,514	1,337	2,409	18	5,552	1,097
2009	1,452	1,309	2,259	19	5,300	1,076
2010	1,604	1,361	2,630	21	5,908	1,204
2011	1,499	1,329	2,745	21	5,884	1,152
2012	1,434	1,297	2,711	21	5,748	1,192
2013	1,415	1,287	2,735	21	5,742	1,091
2014	1,455	1,307	2,805	21	5,879	1,084
2015	1,408	1,307	2,722	21	5,737	1,089

10.2 ENVIRONMENTAL APPENDIX

10.2.1 Air Emissions

It was assumed that current or future generation resources would not exceed Vectren's allocated SO_2 and NOx emission allowances. Vectren's fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NOx emissions while the cost of emission control equipment for SO_2 and NOx is factored into any new facilities that would be selected as part of a portfolio.

Figure 10.7 – Air Pollution Control Devices Installed

	FB Culley 2	FB Culley 3	Warrick 4	AB Brown 1	AB Brown 2
Vintage	1966	1973	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP
MATs	Shared w/ U3	Injection	Injection	Injection	Injection
SO_3		Injection	Injection	Injection	injection

[52] Assumes 5.2% Losses
[53] Does not include municipal demand

Figure 10.8 – CSAPR SO_2 Allowances Current through 11/15/2014 & Seasonal NO_X Allowances Current through 11/24/2014

SO_2				
	AB Brown	FB Culley	SIGECO W4	Total
2016	7,894	4,411	2,892	15,197
2017	4,423	3,890	1,620	9,933
2018	4,423	3,890	1,620	9,933
2019	4,423	3,890	1,620	9,933

NOx					
	AB Brown	BAGS	FB Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	1,195	21	1,044	437	2,697
2018	1,195	21	1,044		2,698
2019	1,195	21	1,044	437	2,697

Figure 10.9 – CSAPR Seasonal NOx Allowances Current through 9/16/2016

	AB Brown	BAGS	FB Culley	SIGECO W4	Total
2016	1,214	21	1,060	445	2,740
2017	658	6	465	227	1,356
2018	658	6	465	227	1,356
2019	658	6	465	227	1,356

10.2.2 Solid Waste Disposal

Scrubber by-products from AB Brown are sent to an on-site landfill permitted by Indiana Department of Environmental Management (IDEM). During the fall of 2009, Vectren finalized construction of a dry fly ash silo and barge loading facility that would allow for the beneficial reuse of Vectren-generated fly ash. Since February 2010, the majority of AB Brown fly ash is diverted to the new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri via a river barge loader and conveyor system. This major sustainability project serves to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and transported offsite for recycling into a cement application.

Fly ash from the FB Culley facility is similarly transported off-site for beneficial reuse in cement. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the AB Brown facility in late 2009, FB Culley's fly ash is now transported to the AB Brown loading facility and shipped to the cement plant via river barge. The FB Culley facility sends its bottom ash to the East ash pond via wet sluicing. The pond is approximately 10 acres in size. The West pond (27 acres) no longer receives bottom ash, but continues to accept coal pile run-off and general storm water from the west side of the plant, including the plant entrance road. Scrubber by-product generated by the FB Culley facility is also used for beneficial reuse and shipped by river barge from FB Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site, but is being recycled and shipped off-site for beneficial reuse.

10.2.3 Hazardous Waste Disposal

Vectren's AB Brown and FB Culley plants are episodic producers of hazardous waste that may include paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Conditionally Exempt Small Quantity Generators.

10.2.4 Water Consumption and Discharge

AB Brown and FB Culley currently discharge process and cooling water to the Ohio River under National Pollutant Discharge Elimination System (NPDES) water discharge permits issued by the Indiana Department of Environmental Management (IDEM). AB Brown utilizes cooling towers while FB Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission (ORSANCO) regional water quality standards mercury limit of 12 ppt monthly average.

10.3 DSM APPENDIX

10.3.1 Gross Savings 2016-2017 Plan

Figure 10.10 – 2016-2017 Plan Gross kWh Energy Savings

	2016*		2017**	
Sector	Gross kWh Energy Savings	kW Demand Savings	Gross kWh Energy Savings	kW Demand Savings
Residential	23,528,418	6,400	20,362,245	4,439
Commercial & Industrial	18,796,505	2,800	17,428,270	2,669
Total	42,324,923	9,200	37,790,515	7,108

*2016 Operating Plan used for 2016

**2016-2017 Filed Plan used for 2017

10.3.2 DSM Programs

Vectren has offered tariff based DSM resource options to customers for a number of years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all of Vectren's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized Vectren to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938, and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP, and HLF.

10.3.3 Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 10.11 – 2016 Electric DSM Operating Plan Program Savings

Program	Residential/ Commercial	Particicpants	NTG	Gross kWh	Gross kWh/ Participant	Net kWh	Gross KW	Gross KW/ Participant	Net KW
Residential Lighting	Residential	314,618	67%	7,923,516	25	5,308,756	1,167	0.004	782
Home Energy Assessments	Residential	1,500	98%	2,048,260	1,366	2,007,295	262	0.17	257
Income Qualified Weatherization	Residential	485	100%	1,103,043	2,274	1,103,043	240	0.49	240
Appliance Recycling	Residential	950	54%	-	-	-	152	0.19	82
Energy Efficient Schools	Residential	2,400	100%	739,963	308	739,963	115	0.05	115
Residential Efficient Products	Residential	4,643	52%	1,997,855	430	1,038,885	918	0.20	477
Residential New Construction	Residential	103	50%	260,756	2,532	130,378	168	1.63	84
Residential Behavioral Savings	Residential	49,751	100%	8,200,000	165	8,200,000	1,400	0.03	1,400
Multi-Family CFL's	Residential	985	100%	326,240		326,240	29	0.03	29
Conservation Voltage Reduction	Residential		100%	-		-	-		-
Nest Demand Response Pilot	Residential	1,000	80%	429,000	429	343,200	900	0.90	720
Honeywell Demand Response Pilot	Residential	1,000	80%	429,000	429	343,200	900	0.90	720
Nest On-Line	Residential	165	100%	70,785	429	70,785	149	0.90	149
Small Business Direct Install	Commercial	26,037	95%	6,619,675	254	6,288,691	878	0.03	834
Commercial & Industrial Prescriptive	Commercial	12,540	87%	6,911,630	551	6,013,119	1,303	0.10	1,134
Commercial & Industrial New Construction	Commercial	15	100%	519,000	34,600	519,000	94	6.27	94
Commercial & Industrial Custom	Commercial	25	100%	4,296,200	171,848	4,296,200	525	21.01	525
Building Tune-Up	Commercial	9	100%	450,000	50,000	450,000	-	-	-
Conservation Voltage Reduction	Commercial		0%	-					
Total		416,226	88%	42,324,923	102	37,178,754	9,200	0.02	7,642

Figure 10.12 – 2017 Electric DSM Filed Planned Savings

Program	Residential/ Commercial	Participants	NTG	Gross kWh	Gross kWh per Participant	Net kWh	Gross KW	Gross kWh per Participant	Net KW
Residential Lighting	Residential	233,899	67%	6,831,909	29	4,577,379	865	0.004	580
Home Energy Assessments	Residential	2,125	98%	1,935,719	911	1,897,004	290	0.14	284
Income Qualified Weatherization	Residential	564	100%	1,282,577	2,274	1,282,577	254	0.45	254
Appliance Recycling	Residential	952	54%	1,020,544	1,072	551,094	152	0.16	82
Energy Efficient Schools	Residential	2,400	100%	675,508	281	675,508	106	0.04	106
Residential Efficient Products	Residential	2,216	52%	1,075,888	486	559,462	623	0.28	324
Residential New Construction	Residential	103	50%	146,775	1,425	73,388	68	0.66	34
Residential Behavioral Savings	Residential	43,500	100%	5,576,656	128	5,576,656	1,553	0.04	1,553
Multi-Family CFL's	Residential	5,500	100%	335,000	61	335,000	20	0.00	20
Conservation Voltage Reduction	Residential	5,324	100%	1,481,669	278	1,481,669	508	0.10	508
Nest Demand Response Pilot	Residential		80%	-		-	-		-
Honeywell Demand Response Pilot	Residential		80%	-		-	-		-
Nest On-Line	Residential		100%	-		-	-		-
Small Business Direct Install	Commercial	17,235	95%	6,000,810	348	5,700,770	906	0.05	861
Commercial & Industrial Prescriptive	Commercial	12,222	87%	6,910,197	565	6,011,871	1,088	0.09	947
Commercial & Industrial New Construction	Commercial	15	100%	534,135	35,609	534,135	94	6.27	94
Commercial & Industrial Custom	Commercial	25	100%	2,906,300	116,252	2,906,300	385	15.40	385
Multi Family Retrofit Pilot Program	Commercial	100	100%	201,785	2,018	201,785	33	0.330	33
Conservation Voltage Reduction	Commercial	558	100%	875,044	1,568	875,044	163	0	163
Total		326,738	87%	37,790,515	116	33,239,641	7,075	0.02	6,227

10.3.4 Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed operations and maintenance cost. For this avoided cost analysis, a 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost. Avoided capacity costs should only be considered avoidable when there is a planning reserve margin deficit that would otherwise need to be met through a new capacity resource.

The marginal operating energy costs were based off the modeled Vectren system marginal energy cost from the base optimized scenario under base assumptions. This included emission cost for CO_2 starting in 2024, estimated capital, variable operation and maintenance, and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses. The table below shows avoided costs.

Figure 10.13 – Avoided Costs[54]

	Natural Gas Forecast $/MMBTu	CO_2 Forecast $/Short Ton	Economic Carrying Charge[55] $/kW	Transmission/ Distribution Avoided Cost $/kW (10% of Carrying Charge)	Total Capacity Avoided Cost $/kW	System Marginal Cost $/MWh	System Marginal Cost $/kWh
2017	$2.94		$91.82	$9.18	$101.00	$28.62	$0.02862
2018	$3.13		$92.55	$9.25	$101.80	$30.93	$0.03093
2019	$3.65		$93.41	$9.34	$102.76	$33.95	$0.03395
2020	$3.90		$94.99	$9.50	$104.49	$35.90	$0.03590
2021	$4.05		$96.77	$9.68	$106.45	$36.09	$0.03609
2022	$4.23		$98.30	$9.83	$108.13	$36.61	$0.03661
2023	$4.40		$100.00	$10.00	$110.00	$36.73	$0.03673
2024	$4.63	$2.29	$100.85	$10.09	$110.94	$40.78	$0.04078
2025	$4.77	$3.70	$102.19	$10.22	$112.41	$42.19	$0.04219
2026	$4.97	$5.87	$103.89	$10.39	$114.27	$44.98	$0.04498
2027	$5.22	$9.83	$106.32	$10.63	$116.95	$49.09	$0.04909
2028	$5.45	$12.71	$107.73	$10.77	$118.51	$52.58	$0.05258
2029	$5.68	$17.54	$109.23	$10.92	$120.15	$57.65	$0.05765
2030	$5.90	$19.50	$110.56	$11.06	$121.62	$60.23	$0.06023
2031	$6.07	$21.11	$112.38	$11.24	$123.62	$62.27	$0.06227
2032	$6.32	$23.60	$114.21	$11.42	$125.64	$65.42	$0.06542
2033	$6.46	$23.63	$115.76	$11.58	$127.33	$66.61	$0.06661
2034	$6.67	$24.58	$117.42	$11.74	$129.17	$68.66	$0.06866
2035	$6.89	$26.34	$119.98	$12.00	$131.98	$71.30	$0.07130
2036	$7.13	$28.14	$122.37	$12.24	$134.60	$73.90	$0.07390

10.4 RESOURCE SCREENING APPENDIX

10.4.1 Busbar Analysis

[54] Reflective of the 2016 IRP Base Scenario Optimized Case B as of September 20, 2016
[55] Economic Carrying Charge is not an avoidable cost if there is no capacity requirement

Figure 10.14 – New Construction Alternatives

Resource[56]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
LM6000 Simple Cycle Gas Turbine	43.4	Natural Gas	Rejected	Not cost effective compared to alternatives
LMS100 Simple Cycle Gas Turbine	99.5	Natural Gas	Rejected	Not cost effective compared to alternatives
E-Class Simple Cycle Gas Turbine	90.1	Natural Gas	Rejected	Not cost effective compared to alternatives
F-Class Simple Cycle Gas Turbine	**220**	**Natural Gas**	**Accepted**	**Cost effective**
1x1 7EA CCGT	170	Natural Gas	Rejected	Not cost effective compared to alternatives
1x1 7FA.05 CCGT	**442**	**Natural Gas**	**Accepted**	**Cost effective for size**
2x1 7FA.04	**745**	**Natural Gas**	**Accepted (select scenarios)**	**Not cost effective compared to alternatives**
2x1 7FA.05	**889**	**Natural Gas**	**Accepted**	**Cost effective for size**
3x1 7FA.05	1337	Natural Gas	Rejected	Exceeds capacity needs
1 MW Microturbine	1.0	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
3 MW Combustion Turbine	3.2	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
5 MW Combustion Turbine	5.1	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
10 MW Combustion Turbine	10.3	CHP-Natural Gas	Rejected	Not cost effective compared to alternatives
14 MW Combustion Turbine	**13.6**	**CHP-Natural Gas**	**Accepted**	**Cost effective CHP**
Supercritical Pulverized Coal 500 MW with Carbon Capture	430	Coal	Rejected	Not cost effective compared to alternatives
Supercritical Pulverized Coal 750 MW with Carbon Capture	640	Coal	Rejected	Not cost effective compared to alternatives
2x1 Integrated Gasification Combined Cycle with Carbon Capture	480	Coal	Rejected	Not cost effective compared to alternatives
Wood Stoker Fired	50	Wood Biomass	Rejected	Not cost effective

[56] Combined cycle gas turbines are shown as duct fired configuration for this table.

Resource[56]	Net Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative	Reason to Accept or Reject
				compared to alternatives
Landfill Gas IC Engine	5	Landfill Gas	Rejected	Not cost effective compared to alternatives
Lithium Ion (10 MW/40 MWh)	**10**	**Battery Storage**	**Accepted (select scenarios)**	**Cost effective battery**
Lithium Ion (1 MW/4 MWh)	1	Battery Storage	Rejected	Not cost effective compared to alternatives
Commercial Battery (0.1 MW/0.25 MWh)	0.1	Battery Storage	Rejected	Not cost effective compared to alternatives
Residential Battery (0.002 MW/ 0.007 MWh)	.002	Battery Storage	Rejected	Not cost effective compared to alternatives
Compressed Air Energy Storage	100	Storage	Rejected	Not feasible in Vectren's service territory
Wind (North Dakota 50 MW)	50	Renewables	Rejected	Transmission costs are cost prohibitive
Wind (North Dakota 200 MW)	200	Renewables	Rejected	Transmission costs are cost prohibitive
Wind (Indiana 50 MW)	**50**	**Renewables**	**Accepted**	**Low cost renewable energy for size**
Wind (Indiana 200 MW)	**200**	**Renewables**	**Accepted**	**Low cost renewable energy for size**
Solar Photovoltaic (3 MW)	3	Renewables	Rejected	Not cost effective compared to alternatives
Solar Photovoltaic (6 MW)	6	Renewables	Rejected	Not cost effective compared to alternatives
Solar Photovoltaic (9 MW)	**9**	**Renewables**	**Accepted**	**Low cost renewable capacity for size**
Solar Photovoltaic (50 MW)	**50**	**Renewables**	**Accepted**	**Low cost renewable capacity for size**
Solar Photovoltaic (100 MW)	100	Renewables	Rejected	Acreage required may be difficult to find in Vectren's service territory
Hydroelectric	50	Hydroelectric	Rejected	Not cost effective compared to alternatives

10.5 RISK APPENDIX

As described further below, uncertainty is addressed in two different ways: first, by subjecting technologies to a variety of market outcomes in the screening analysis to ensure that Vectren has selected technologies in its portfolios that will perform well in a variety of future conditions, and second, in a more comprehensive risk analysis where the range of future conditions on the selected portfolios is more fully captured.

Key to this more comprehensive risk analysis is a stochastic risk assessment that bounds the uncertainty, captures the variability, and identifies the risk exposure inherent in long-term power generation planning. Variability results from supply and demand disruptions, market conditions, technology improvements, economic cycles, and weather, all of which are captured in Vectren's Risk Integrated IRP approach. To capture this variability, a Monte Carlo simulation is used to evaluate the range of possible futures as well as their likelihoods. The stochastic model estimates probability distributions of potential outcomes by allowing for simultaneous random-walking yet inter-correlated variation in many inputs over time, including gas prices, coal prices, carbon prices, capital costs, and load growth. These boundary conditions and probability bands then help to inform decision making on each portfolio's overall benefit-risk profile.

10.5.1 Stochastics

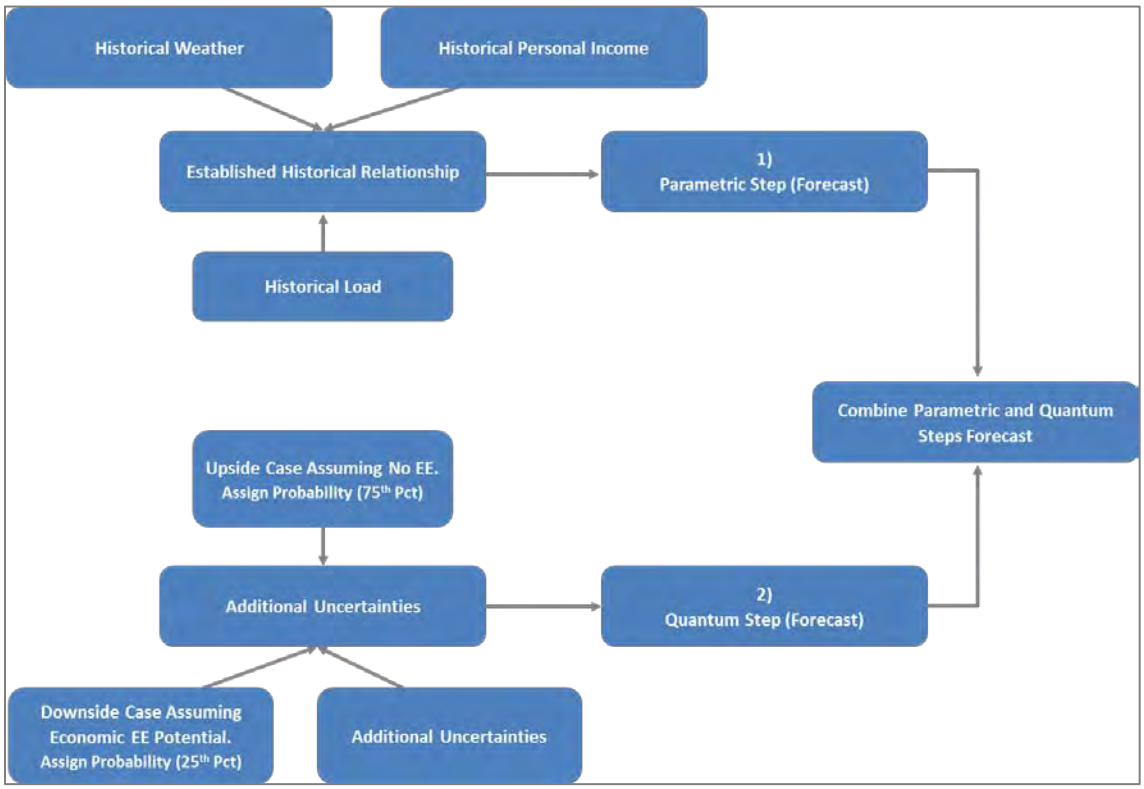
10.5.1.1 Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Pace Global developed stochastics around the load growth expectations for the Vectren control area and the neighboring ISO zones. While values in the 95th percentile are driven by strong economic growth, values in the 5th percentile are driven by economic stagnation as well as energy efficiency and demand-side management implementation.

Pace Global' s long-term load forecasting process is a two-step process that captures both the impact of historical load drivers such as economic growth and variability of weather (parametric step) and the possible disruptive impacts of energy efficiency penetration (quantum step) in constructing the average and peak demand outlook.

Pace Global benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain. The process to benchmark the load to MISO's forecasts was undertaken during the quantum step, which is described below.

Figure 10.15 – Pace Global's Load Forecast Process



The parametric step separately employs a unique econometric model for each MISO Local Resource Zone (LRZ) based on the historical relationships between average and peak load, and key driver variables, including temperature data (HDD, CDD, and humidity) and an economic factor variable (personal income for the geographical area).

Pace Global used the historical personal income drift rates and volatility and a sampling from 17 years of historical data for each region to assess the distribution of overall load growth conditions for each year of the forecast. The base average and demand forecast were based on the average of the peak and average demand forecasts.

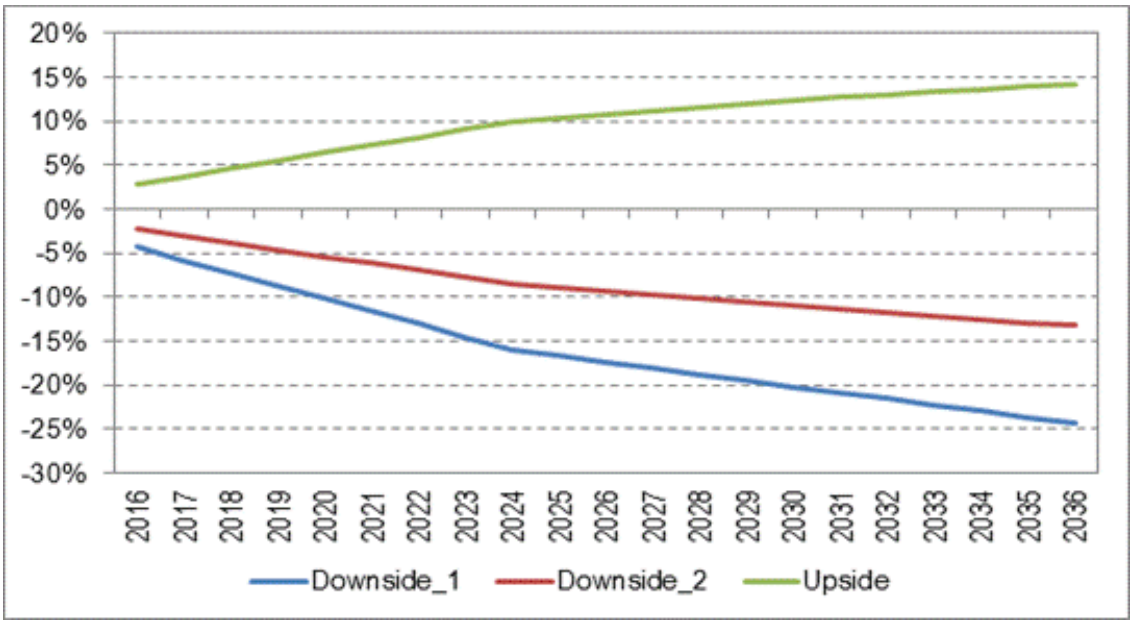
The quantum step assessed the possible disruptive impacts of energy efficiency on the average and peak loads in MISO. Pace constructed three energy efficiency scenarios using publically available FERC and NERC reports data:

1. Upside scenario: No significant savings from efficiency programs
2. Downside scenario 2: Energy efficiency penetration dictated by current economic value
3. Downside scenario 1: Additional energy efficiency penetration driven by federal and state programs to achieve energy efficiency technical potential

In addition, Pace Global used the most recent historical average and peak load for each MISO LRZ and the forecasted compounded annual growth rate (CAGR) of peak and average demand from MISO-sponsored 10 year independent load forecasts to benchmark and formulate a reference.

With this information, Pace Global constructed synthetic distributions for energy efficiency by assigning the upside scenario as the 75th percentile case, the base case scenario as the 50th percentile case, the economic energy efficiency potential as the low 25th percentile, and the technical energy efficiency potential as the 5th percentile. The following graph shows an illustration of the impact of three scenarios on the average demand growth rate. The average impact derived from the synthetic distribution was applied to base demand forecast obtained in the parametric step.

Figure 10.16 – Illustrative Impact of Three Scenarios on Energy Efficiency

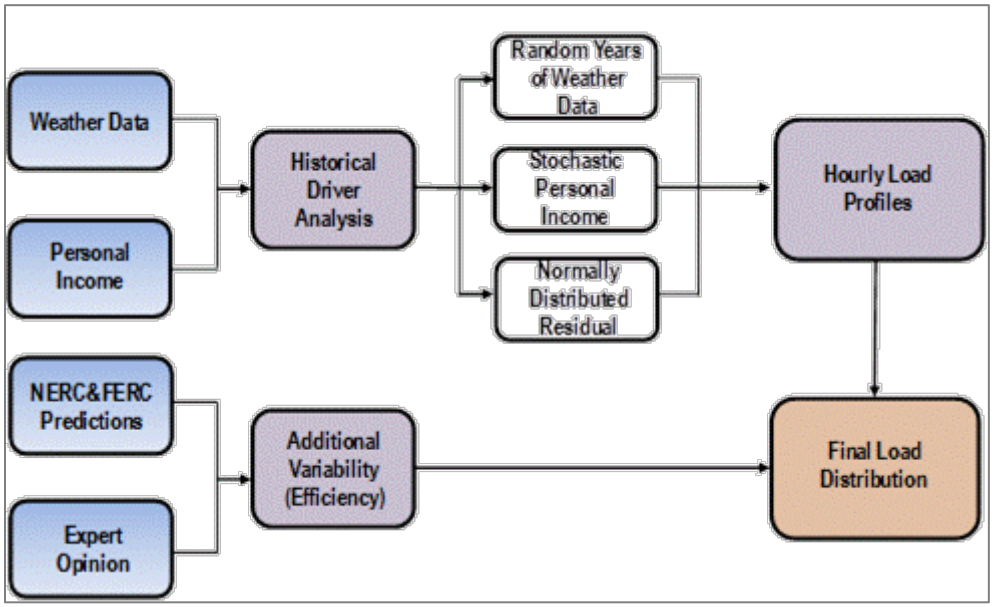


Pace Global benchmarked its outlook against the latest MISO-sponsored load forecasting study, which shows the CAGR for the next 10 year study period. The study report has a CAGR value for each of the nine LRZs. Pace Global applied the CAGR value to the actual 2015 historical load, which is the starting value, and determined a projection of the load forecast. This load forecast was considered as the base case (50th percentile) reference. The previous graph shows the high and two low percentiles as percentage increase/reductions to the reference load. For example, the 5th percentile case has a value of -16% by 2025. The base case reference load for 2025 was reduced by 16%, which corresponds to the technical potential for EE penetration. The same steps were repeated for the 25th percentile and 75th percentile cases for each year, which created a distribution of projections depicting the various "market events" that can happen in the future. For the deterministic case, the average impact from this synthetic distribution was imposed on the load forecast from the parametric step, to obtain the final load forecasts.

To address demand uncertainty in modeling and capture the risk associated with demand growth, Pace Global produced a distribution of monthly average and peak

loads using the methodology described below and summarized in the following flow chart.

Figure 10.17 – Flow Chart to Address Load Uncertainty



With respect to the historical driver analysis, Pace Global finds that historical monthly weather data and personal income explain fairly well the changes in monthly average and peak load. This relationship forms the basis for Pace Global's load uncertainty analysis. The basic premise of the model is that load can be expressed as a function of HDDs, CDDs, humidity, and personal income.

$$Load_t=\alpha+ \beta_1*HDD_t+ \beta_2*CDD_t+ \beta_3*HUM_t+ \beta_4*PI_t+ \xi_t$$

Where:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero (HDD is never negative)
- CDD (Cooling Degree Days): Average daily temperature -65 in degrees Fahrenheit or zero. (CDD is never negative)
- HUM (Humidity): Average daily percent humidity
- PI: Personal Income

- ξ: A normally distributed variable with mean 0 and constant variance
- α: A constant derived from the regression analysis
- β_n: Coefficients derived from the regression analysis

A stepwise regression then calibrated this model to historic data.

The load stochastics propagation was conducted in a two-step process.

Step 1: Weather and Economic Variability

To produce load stochastics, Pace Global propagated three independent random paths: weather data, personal income, and a residual. Weather data includes HDDs, CDDs, and humidity. To produce reasonable weather data projections, Pace Global sampled actual yearly paths from history. On average, Pace uses 17 years of historical data to perform the weather projections for the forward study period. Personal income is assumed to follow Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the return on personal income will behave at any time. Historical personal income data produces a best estimate for the relevant monthly mean and variance of this process going forward. Finally, to account for unexplained variation in the observed data, Pace Global added a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

Step 2: Additional Variability

Pace Global believes that future power demand may differ substantially from past power demand. To accommodate for this possibility, an additional “efficiency distribution” was added to the empirically derived distribution. The distribution is log-normally distributed. The 5th percentile of this distribution is taken primarily from NERC and FERC projections (or other relevant data sources) for statewide potential for load reduction from efficiency or other DSM measures. For example, these measures may include smart meter infrastructure, appliance energy efficiency standards, or other direct load control programs. The upper tail of this distribution was weighted to match Pace

Global's analysis of historical high periods of load growth and Pace Global's expert opinion. Note that the "efficiency distribution" incorporates the potential for limited or no penetration of the expected increases in the energy efficiency of the economy embedded in the base case. Examples include increasing residential plug load or high energy consumption technology breakthroughs. Pace Global expects that changes attributable to the efficiency distribution will affect load growth on a large geographic scale. Accordingly, concurrent energy efficiency changes are highly correlated across regions. Additionally, Pace Global expects that incremental efficiency changes will persist over time. Accordingly, the propagations have a high level of serial correlation.

10.5.1.2 Gas Stochastics

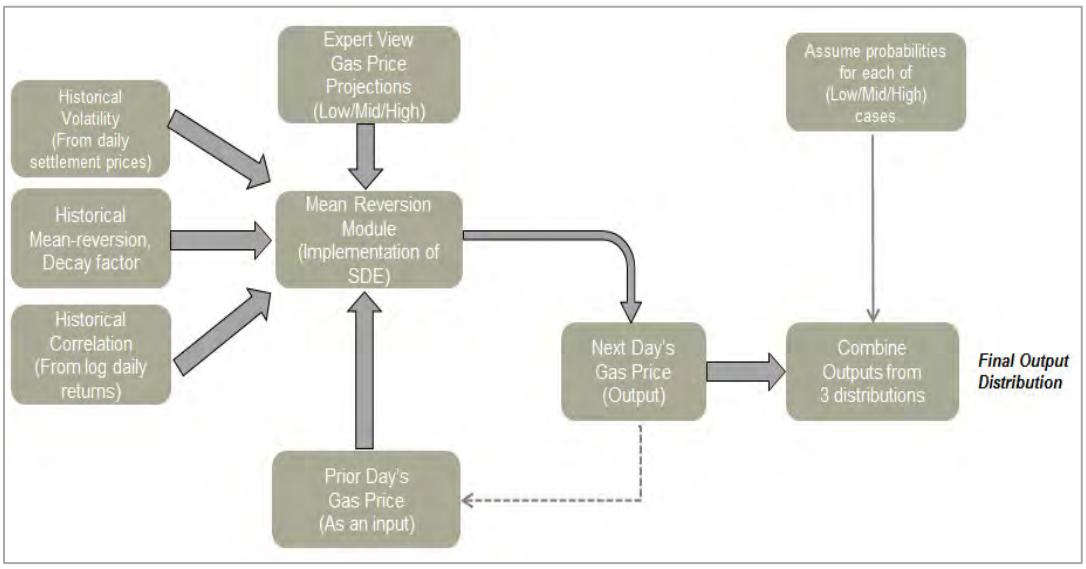
Pace Global developed natural gas stochastic distributions for Henry Hub and other basis points, including points relevant to Indiana. These stochastic distributions are based on a base case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility.

Pace Global developed stochastics around the price at the Henry Hub and other hubs based, including points relevant to Indiana, on historical volatility, current market forwards, and a long-term term fundamental view that takes into account the expected supply-demand balance. To estimate future volatility, the volatility of the last 30 months is applied to 2016-2018, the volatility from 2011-2015 is applied to 2019-2025, and the volatility from 2005-2015 is applied to 2026-2035. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

The steps involved in the development of gas stochastics are as follows:

- As the first step, Pace developed the long-term fundamental forecast of Henry Hub and many other North American gas hub bases to the Henry Hub (using the Gas Pipeline Competition Model or GPCM). The probability distributions were developed around this fundamental forecast.
- From historical data sets, the volatility parameter was calculated using the daily settled prices. Volatilities for different historical time periods were calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The daily gas prices were modeled as a single-factor continuous mean-reverting process. The mean reversion parameter was also calculated from the historical daily settled prices.
- For several gas hub bases that are deemed to be correlated, the appropriate correlations were calculated from the historical data.
- The entire process to develop the gas stochastics is described in the exhibit below:

Figure 10.18 – Pace Global's Gas Stochastics Process



- The volatilities tend to vary for different time periods. In order to capture this for the forecast time period, different volatility values from different historical time

periods were considered. For example, for the first three forecast years (2016-2018), volatility calculated from the past 30 months price data is used. For years 4-10 (2019-2025), volatility calculated from the past five years (2011-2015) is used. Beyond that time period (2026-2035), the past 10-year historical volatility (2005-2015) is used.

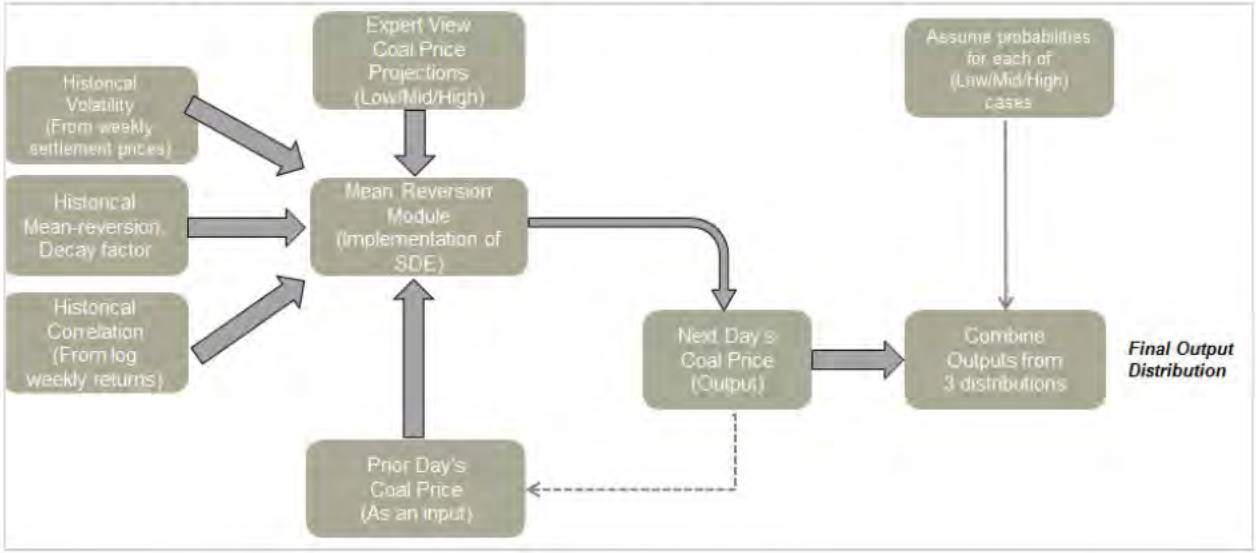
- The long-term fundamental forecast for each month in the forecast time period was treated as the mean-reverting level in this process.

10.5.1.3 Coal Stochastics

Pace Global developed coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins. These stochastic distributions are based on a reference case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters. It should be noted that a majority of coal contracts in the U.S. are bilateral and only about 20 percent are traded on the NYMEX. The historical data set that was used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

The methodology involved in the distribution of stochastic coal prices is exactly the same as that used for natural gas stochastics.

Figure 10.19 – Pace Global's Coal Stochastics Process



The steps involved in the development of coal basin price stochastics are as follows:

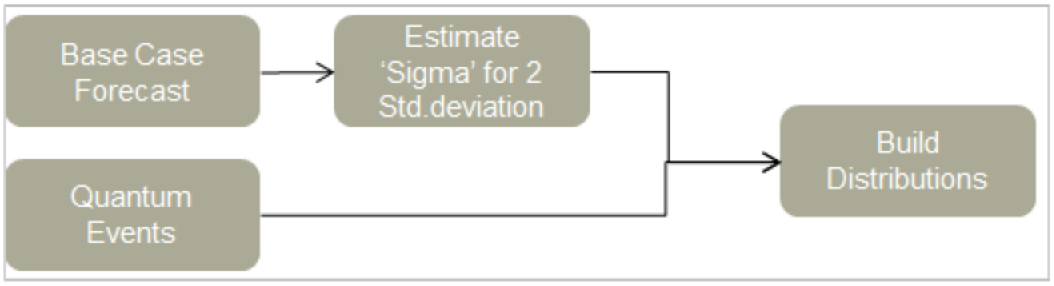
- As the first step, Pace developed the long-term fundamental forecast of each of the coal basins. The probability distributions were developed around these fundamental forecasts.
- From historical data sets, the volatility parameter was calculated using weekly prices. Volatilities for different historical time periods were calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The coal prices were modeled as a single-factor continuous mean-reverting process. The mean reversion parameter was also calculated from the historical prices.
- For the four coal basin prices, the appropriate correlations were calculated from the historical data.

10.5.1.4 Emissions Stochastics

Pace Global developed uncertainty distributions around carbon compliance costs, which were used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

The technique to develop carbon costs distributions, unlike the previous variables, is based on Pace Global' expert opinion based projections. There are no historical data sets to estimate the parameters for developing carbon costs distributions. Accordingly, the views of Pace Global's subject matter experts are taken into consideration. The exhibit below shows the high level methodology for developing stochastic distributions, when the historical data is not available.

Figure 10.20 – Pace Global's Emissions Stochastics Process



Given below are the steps involved in this process:

- Pace's environmental team developed a base case forecast, and an associated high and low case. In addition to the high and low cases, the probability values for the high and low cases were developed.
- These three cases are treated as 16th, 50th and 84th percentiles. Using these percentiles and statistical techniques, the standard deviation values were calculated.
- The base case is treated as the mid-case (median).
- Using the standard deviation values and a sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands were constructed around the reference projections. This underlying distribution captures the quantum events that can happen in the market.
- The distributions were then adjusted to incorporate probabilities such as "*the probability of a CO_2 program not taking effect*" and "*a greater chance of a nation-wide CO_2 regime starting in 2022,*" etc.

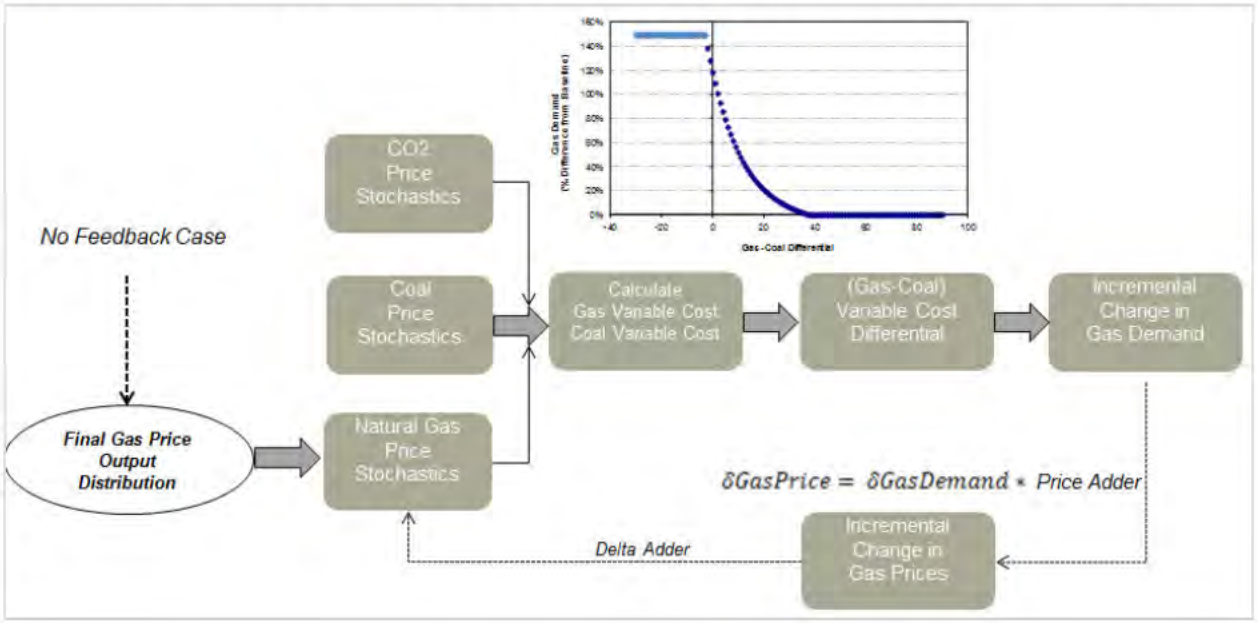
- Separate distributions were developed for national carbon costs, California carbon costs, and RGGI prices, which were then applied to the respective states.

10.5.1.5 Gas-Coal-CO_2 Prices Feedback (Cross-Commodity Correlations) Stochastics

Pace Global has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes. This is a separate process which is implemented after modeling the gas, coal, and CO2 processes discussed above.

The exhibit below describes the coal and CO_2 feedback loops that affect gas prices. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators.

Figure 10.21 – Pace Global's Cross-Commodity Correlation Stochastics Process



- Pace performed fundamental analysis to define the relationship between gas-coal dispatch cost and demand; incremental gas demand curve as a function of the gas-coal differential was calibrated.

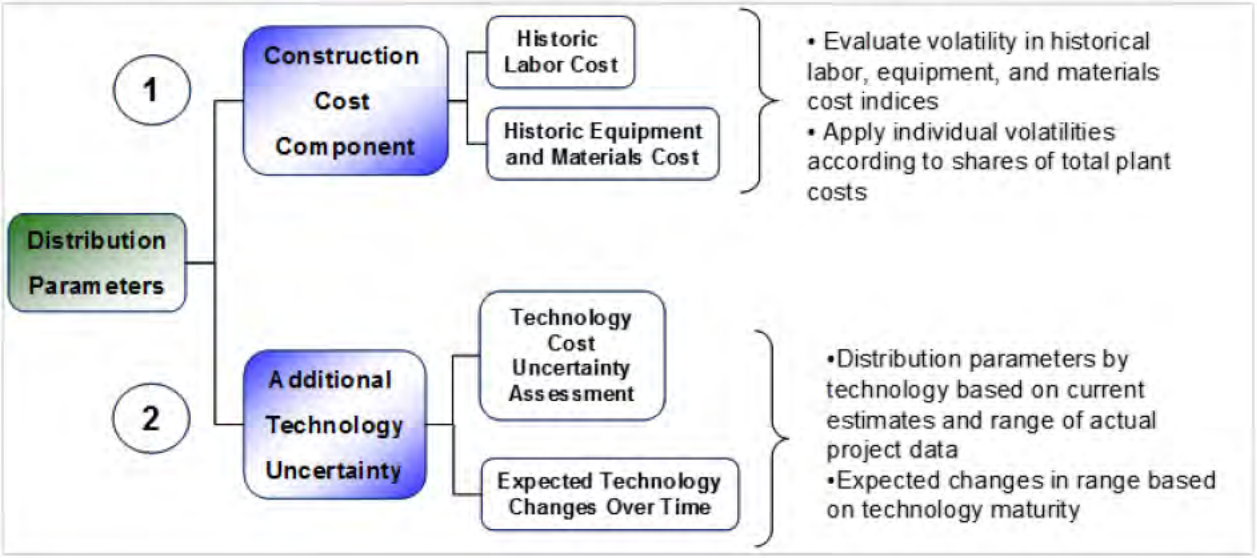
- For each iteration, the dispatch cost of gas and coal was calculated from the fuel stochastics and CO_2 stochastics, along with generic assumptions for VOM.
- If the gas-coal dispatch differential changes significantly enough to affect demand, the gas demand from the previous year was adjusted to reflect the corresponding change in demand.
    - Adjustment can happen in both directions
- A gas price delta was then calculated based on the defined gas demand – price relationship developed.

This gas price delta is added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

10.5.1.6 Capital Cost Stochastics

Pace developed the uncertainty distributions for the cost of new entry units by technology types, which were used in the Aurora dispatch model for determining the economic new builds based on market signals. The exhibit below describes the methodology at a high level:

Figure 10.22 – Pace Global's Capital Cost Stochastics Process



The methodology of develop the capital cost distributions is a two-step process:

Step 1:

Parametric Distribution:
Pace Global's subject matter experts provided a reference case forecast of $/KW all-in capital costs for different technology types. Along with it, high and low case forecasts were also developed.

The plant costs were broken down into four categories: Equipment, Materials, Labor, and Other. Historical data (from the Handy-Whitman Index) was used to estimate mean price changes and volatilities in these cost categories.

Suitable weights were allocated to each of these four categories. The weighted average of the historical mean and volatilities were then estimated.

Using the mean and volatility values, and sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands were constructed around the base case forecast.

Step 2:

Quantum Distribution:
This step captured the additional uncertainty associated with each technology. It also factored in the learning curve effects, improvements in technology over time, and other uncertain events.

The expert opinion based high and low cases were treated as one standard deviation from the mean. With this assumption, the variance values were calculated.

To determine the probability distributions, a log-normal distribution was assumed. This distribution was combined with the parametric distribution obtained in the previous step, to come up with the final set of distributions.

10.5.2 Rate Metric Ranking

Figure 10.23 – Aurora 20-Year Mean NPV $ Billion

Portfolio	20 Year NPV[57]	% above lowest cost
H: Heavy Gas	$ 3.02	
B: Heavy Gas	$ 3.03	0.0%
G: Gas & Solar	$ 3.06	1.0%
D: Gas & Wind	$ 3.07	1.4%
E: Heavy Gas	$ 3.10	2.5%
K: Diversified w/ Coal	$ 3.12	3.1%
N: Gas & Solar	$ 3.12	3.1%
O: Gas & Solar	$ 3.12	3.3%
L: Diversified w/ Coal	$ 3.15	4.1%
M: Diversified w/ Coal	$ 3.16	4.3%
C: Gas & Solar	$ 3.16	4.6%
F: Gas & Wind	$ 3.17	4.9%
A: Existing Portfolio	$ 3.21	6.3%
I: Stakeholder w/ Renewables	$ 3.86	27.6%
J: Stakeholder w/ Renewables	$ 4.21	39.3%

[57] The NPV of energy procurement is an indicative component of rates

Figure 10.24 – Aurora 20-Year Weighted Energy Procurement Cost[58]

Portfolio	20 Year $/kWh	% above lowest cost
H: Heavy Gas	0.064	
B: Heavy Gas	0.064	0.0%
G: Gas & Solar	0.065	1.0%
D: Gas & Wind	0.065	1.4%
E: Heavy Gas	0.066	2.5%
K: Diversified w/ Coal	0.066	3.1%
N: Gas & Solar	0.066	3.1%
O: Gas & Solar	0.066	3.3%
L: Diversified w/ Coal	0.067	4.1%
M: Diversified w/ Coal	0.067	4.3%
C: Gas & Solar	0.067	4.6%
F: Gas & Wind	0.067	4.9%
A: Existing Portfolio	0.068	6.3%
I: Stakeholder w/ Renewables	0.082	27.6%
J: Stakeholder w/ Renewables	0.089	39.3%

10.6 TRANSMISSION APPENDIX

10.6.1 Transmission and Distribution Planning Criteria

Vectren continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of Vectren's planning process can be summarized as follows:

a) Developing a transmission system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet Vectren customers' needs during normal conditions and during a system contingency or set of contingencies;

[58] The NPV of energy procurement is an indicative component of rates

b) Minimizing thermal loadings on transmission facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
c) Analyzing the dynamic stability of the transmission system under various contingency conditions;
d) Ensuring the fault current duty imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
e) Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
f) Coordinating transmission planning activities in broader regional evaluations with the Midcontinent Independent System Operator (MISO), ReliabilityFirst (RF), and neighboring transmission owners;
g) Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
h) Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
i) Analyzing the performance of its distribution system to ensure reliability, adequacy to meet future load growth, and to address age and condition of existing facilities; and
j) Ensuring compliance with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) and RF Reliability Standards for transmission planning.

10.6.2 MISO Regional Transmission Planning

The Midcontinent Independent System Operator (MISO) performs the North American Electric Reliability Corporation (NERC) functional role of Planning Coordinator on behalf of Vectren. In its NERC functional role of Transmission Planner, Vectren supports MISO's regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. Vectren is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

Vectren participates in MISO coordinated seasonal transmission assessments (CSAs) for spring, summer, fall and winter peak loads. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. Vectren also participates in MISO Generator Interconnection and Transmission Service Requests planning processes as required.

Vectren participates in MISO's regional Transmission Expansion Plan (MTEP). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets, and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved a 345kV Market Efficiency Project between Vectren's Duff substation and Big Rivers Electric Corporation's Coleman EHV substation during the MTEP 2015 planning cycle. The project is expected to be in-service by the beginning of 2021. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line. Vectren partnered with PSEG in submitting a proposal to MISO to construct the line. Vectren, as the incumbent transmission owner, will be responsible for the Duff substation modifications required for the project. The overall project cost is shared

according to MISO's Tariff. The project not only provides regional economic benefits, but also enhances grid reliability in the area of Vectren's Newtonville substation.

10.6.3 Annual Transmission Assessment

Vectren's most recent transmission assessment was completed in 2015. The study used the final NERC Multiregional Modeling Working Group (MMWG) 2014 Series Models, which includes the Vectren full detailed model. The MMWG is responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are used by the NERC Regions and their member systems in planning future performance and evaluating current operating conditions of the interconnected bulk electric systems. Siemens PTI PSS/E version 33.6.0 software was used to conduct the assessment.

Vectren's internal planning procedures direct the specific tasks and methods for conducting this study. The internal procedures also define the ratings methodology used for the existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson (FDNS) solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled, and VAR limits applied automatically. Dynamic simulations were not completed in 2015, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with MTEP-14 and the RF MMWG Seasonal Assessments.

The Vectren Bulk Electrical System (100kV and above) is expected to be stable and perform well over the next 10 years. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, Vectren plans projects to mitigate the violations.

The loss of the two 138kV lines into Toyota substation results in the loss of service to the facility. A new 138kV line from Toyota substation to Scott Township substation is proposed. This line will also provide a second line into Scott Township substation, which is on a radial 138kV line. Scott Township substation provides voltage support for most of the load along the Highway 41 North corridor. This proposed line will also become a parallel path to the Francisco to Elliott 138kV line and increases post-contingent import capability.

Other notable contingencies (N-1-1) include the loss of load in the Mt. Vernon, IN area. The area is served by three 138kV lines. The outage of any two feeds causes voltage issues in the area and potential thermal overloads on the remaining line. The proposed customer-owned Co-Generation facility has the potential to reduce this large customer's load and eliminate this potential issue. Additional capacitor banks and upgrades could mitigate this issue as well. The only mentionable extreme contingency is also for the Mt. Vernon area for the complete loss of the A.B. Brown 138kV substation. This substation loss has the potential to cause voltage loss to the Mt. Vernon area and numerous large industrial customers. NERC requirements do not require that Vectren prevent this event. The standards only require that extreme contingencies not cause cascading outage and impair the Bulk Electric System (BES). The electric transmission system outside of Mt. Vernon is not affected; however, an outage of this magnitude would require a notification to NERC.

Several 69kV lines are proposed as alternate feeds to reduce outage times.

- A new 69kV line to be installed between Mohr Rd and St. Wendell substations (scheduled in-service date of 12/31/2016).
- A new 69kV line to be installed between Boonville and Boonville Pioneer Substation (scheduled in-service date of 12/31/2018).
- Extend an existing 69kV line to provide a third source into the Jasper area from Dubois substation (scheduled in-service date of 12/31/2017).

These are not NERC reliability driven projects, but should reduce outage durations to customers caused by transmission outages in these areas and should improve reliability indices and metrics.

Toyota South, Roesner Road and Adam Street are new distribution substations currently proposed to meet load growth. The Adams Street substation project also facilitates 4kV to 12kV conversion projects.

SECTION 11
TECHNICAL APPENDIX ATTACHMENTS

Attachment 1.1 Non-Technical Summary

Confidential Attachment 1.2 2016 Vectren Technology Assessment Summary Table

Attachment 3.1 Stakeholder Materials

Attachment 4.1 2016 Vectren Long-Term Electric Energy and Demand Forecast Report

Attachment 4.2 2015 Vectren Hourly System Load Data

Attachment 4.3 2016 MISO LOLE Study Report

Attachment 5.1 Vectren South Electric 2016-2017 DSM Plan

Confidential Attachment 5.2 CCGT Site Selection Report

Attachment 5.3 Cost of Energy Efficiency Programs

Confidential Attachment 5.4 CHP Market Potential Study

Attachment 7.1 IRP Portfolio Summary Report

Attachment 7.2 Balance of Loads and Resources

Confidential Attachment 7.3 Portfolio Input-Output Report

Attachment 7.4 Economic Impact Study - Economic Ripple Effects of Diversifying the Power Generation Portfolio

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 109
Culley East Ash Pond Extension Demonstration

VECTREN
A CenterPoint Energy Company

Vectren
P.O. Box 209
Evansville, IN 47702-0209

November 24, 2020

Sent electronically via File Transfer

Mr. Andrew Wheeler
Administrator, US EPA
1200 Pennsylvania Avenue, N.W.
Mail Code: 5304-P
Washington, D.C. 20460

Subject: Request for Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment
Development of Alternative Capacity is Technically Infeasible Demonstration
SIGECO F.B. Culley Generating Station, Newburgh, Warrick County, Indiana

Dear Mr. Wheeler:

Southern Indiana Gas and Electric Company, Inc. (SIGECO) hereby submits this request for an extension to the "cease receipt" deadline for the F.B. Culley Generating Station (F.B. Culley) East Ash Pond pursuant to the *Development of Alternative Capacity is Technically Infeasible* criteria under 40 CFR § 257.103(f)(1).

The attached report has been prepared in accordance with the requirements of 40 CFR 257.103(f)(1) to demonstrate that obtaining alternative capacity for the CCR and non-CCR flows at the SIGECO F.B. Culley East Ash Pond is infeasible before the April 11, 2021 "cease receipt" deadline provided in 40 CFR § 257.101(a)(1). Accordingly, SIGECO is respectfully requesting an extension of the "cease receipt" deadline to March 1, 2023 for the East Ash Pond. The basis for this request is detailed in the attached document. To aid in your verification of completeness, a regulatory checklist summarizing where each regulatory requirement has been included in the report, immediately following the Table of Contents.

We trust this provides the information you need to process this application. As allowed and preferred by the agency, in lieu of hard copies of the demonstration packet, the submittal format is via email with a file transfer link to Kirsten Hillyer, Frank Behan, and Richard Huggins. Should you need additional information on this submittal, please don't hesitate to contact me at 812-491-4787 or Angela.Casbon-Scheller@centerpointenergy.com.

Sincerely,

Angela Casbon-Scheller
Manager, Environmental Operations
Power Generation

cc: Kirsten Hillyer (Hillyer.Kirsten@epa.gov)
Frank Behan (Behan.Frank@epa.gov)
Richard Huggins (Huggins.Richard@epa.gov)

AECOM Imagine it. Delivered.

Submitted to
Southern Indiana
Gas & Electric Company
(SIGECO)
One Vectren Square
Evansville, IN 47708

Submitted by
AECOM
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202

November 24, 2020

Request for Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment

Development of Alternative Capacity is Technically Infeasible Demonstration (40 CFR § 257.103(f)(1)) for the East Ash Pond at the F.B. Culley Generating Station

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Figure 10 SDE Process Flow Diagram

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Appendix A IURC Order in Cause No. 45052
Appendix B Schedule Activities and Milestones
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Addendum

Appendix A Groundwater Monitoring Program
Appendix B Annual Groundwater Monitoring and Corrective Action Reports
Appendix C Groundwater Flow Direction (April 2017)
Appendix D Work Plan to Install Monitoring Wells and Piezometers
Appendix E Location of Monitoring Wells
Appendix F Notification of Initiation of Corrective Measures Assessment

Regulatory Checklist

Regulatory Reference	Description of Requirement	Report Section
257.103 (f)(1)(iv)(A)(1)	*A written narrative discussing the options considered both on and off-site to obtain alternative capacity for each Coal Combustion Residual (CCR) and/or non-CCR wastestreams, the technical infeasibility of obtaining alternative capacity prior to April 11, 2021, and the option selected and justification for the alternative capacity selected. The narrative must also include all of the following:*	**5.0**
257.103 (f)(1)(iv)(A)(1)(i)	*An in-depth analysis of the site and any site-specific conditions that led to the decision to select the alternative capacity being developed;*	**5.1.4**
257.103 (f)(1)(iv)(A)(1)(ii)	*An analysis of the adverse impact to plant operations if the CCR surface impoundment in question were to no longer be available for use; and*	**5.1.5**
257.103 (f)(1)(iv)(A)(1)(iii)	*A detailed explanation and justification for the amount of time being requested and how it is the fastest technically feasible time to complete the development of the alternative capacity;*	**5.1.6**
257.103 (f)(1)(iv)(A)(2)	*A detailed schedule of the fastest technically feasible time to complete the measures necessary for alternative capacity to be available including a visual timeline representation. The visual timeline must clearly show all of the following:*	**5.2**
257.103 (f)(1)(iv)(A)(2)(i)	*How each phase and the steps within that phase interact with or are dependent on each other and the other phases;*	**5.2**
257.103 (f)(1)(iv)(A)(2)(ii)	*All of the steps and phases that can be completed concurrently;*	**5.2**
257.103 (f)(1)(iv)(A)(2)(iii)	*The total time needed to obtain the alternative capacity and how long each phase and step within each phase will take; and*	**5.2**
257.103 (f)(1)(iv)(A)(2)(iv)	*At a minimum, the following phases: Engineering and design, contractor selection, equipment fabrication and delivery, construction, and start up and implementation.;*	**5.2**
257.103 (f)(1)(iv)(A)(3)	*A narrative discussion of the schedule and visual timeline representation, which must discuss all of the following:*	**5.2**
257.103 (f)(1)(iv)(A)(3)(i)	*Why the length of time for each phase and step is needed and a discussion of the tasks that occur during the specific step;*	**5.2**
257.103 (f)(1)(iv)(A)(3)(ii)	*Why each phase and step shown on the chart must happen in the order it is occurring;*	**5.2**
257.103 (f)(1)(iv)(A)(3)(iii)	*The tasks that occur during each of the steps within the phase; and*	**5.2**
257.103 (f)(1)(iv)(A)(3)(iv)	*Anticipated worker schedules*	**5.2.2.8**
257.103 (f)(1)(iv)(A)(4)	*A narrative discussion of the progress the owner or operator has made to obtain alternative capacity for the CCR and/or non-CCR wastestreams. The narrative must discuss all the steps taken, starting from when the owner or operator initiated the design phase up to the steps occurring when the demonstration is being compiled. It must discuss where the facility currently is on the timeline and the efforts that are currently being undertaken to develop alternative capacity.*	**5.3**
257.103 (f)(1)(iv)(B)	*To demonstrate that the criteria in paragraph (f)(1)(iii) of this section have been met, the owner or operator must submit all of the following:*	**6.0**

Regulatory Reference	Description of Requirement	Report Section
257.103 (f)(1)(iv)(B)(1)	*A certification signed by the owner or operator that the facility is in compliance with all of the requirements of this subpart;*	**6.1**
257.103 (f)(1)(iv)(B)(2)	*Visual representation of hydrogeologic information at and around the CCR unit(s) that supports the design, construction and installation of the groundwater monitoring system. This includes all of the following:*	**6.2**
257.103 (f)(1)(iv)(B)(2)(i)	*Map(s) of groundwater monitoring well locations in relation to the CCR unit(s);*	**6.2.1**
257.103 (f)(1)(iv)(B)(2)(ii)	*Well construction diagrams and drilling logs for all groundwater monitoring wells; and*	**6.2.2**
257.103 (f)(1)(iv)(B)(2)(iii)	*Maps that characterize the direction of groundwater flow accounting for seasonal variations;*	**6.2.3**
257.103 (f)(1)(iv)(B)(3)	*Constituent concentrations, summarized in table form, at each groundwater monitoring well monitored during each sampling event;*	**6.3**
257.103 (f)(1)(iv)(B)(4)	*A description of site hydrogeology including stratigraphic cross-sections;*	**6.4**
257.103 (f)(1)(iv)(B)(5)	*Any corrective measures assessment conducted as required at 257.96*	**6.5**
257.103 (f)(1)(iv)(B)(6)	*Any progress reports on corrective action remedy selection and design and the report of final remedy at selection required a 257.97 (a)*	**6.6**
257.103 (f)(1)(iv)(B)(7)	*The most recent structural stability assessment required at 257.73 (d)*	**6.7**
257.103 (f)(1)(iv)(B)(8)	*The most recent safety factor assessment required at 257.73 (e)*	**6.8**

Acronyms

ASD	Alternative Source Demonstration
BOD	Biochemical Oxygen Demand
BOP	Balance of Plant
CbR	Closed (or Closure) by Removal
CCR	Coal Combustion Residuals
CFR	Code of Federal Regulations
CiP	Closed (or Closure) in Place
CRW	Clarified River Water
DCS	Distributed Control System
ELG	Effluent Limitation Guidelines
EPA	United States Environmental Protection Agency
F.B. Culley	F.B. Culley Generating Station
FGD	Flue Gas Desulfurization
GPD	Gallons Per Day
GWPS	Groundwater Protection Standards
IDEM	Indiana Department of Environmental Management
IFC	Issued for Construction
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
MGD	Million Gallons per Day
MM	Million
MSL	Mean Sea Level
MW	Megawatt
NPDES	National Pollutant Discharge Elimination System
OLQ	Office of Land Quality
POTW	Publicly Owned Treatment Works
RFP	Request for Proposal
SCC	Submerged Chain Conveyor
SDE	Spray Dryer Evaporator
SIGECO	Southern Indiana Gas and Electric Company
SSLs	Statistically Significant Levels
TSS	Total Suspended Solids
WWTF	Wastewater Treatment Facility
ZLD	Zero-Liquid Discharge

1 Executive Summary

Southern Industrial Gas and Electric Company (SIGECO) owns and operates the F.B. Culley Generating Station (F.B. Culley Generating Station or F.B. Culley) located in Warrick County, Indiana, southeast of Newburgh, Indiana. F.B. Culley Generating Station currently operates the East Ash Pond, a unit that receives both Coal Combustion Residual (CCR) and non-CCR flows associated with the operation of two coal-fired generating units; Unit 2 at 100 megawatts (MW) and Unit 3 at 287 MW. The East Ash Pond is a currently operating surface impoundment which is planning for closure in accordance with the requirements of the United States Environmental Protection Agency's (EPA) Final CCR Rule (40 Code of Federal Regulations (CFR) 257, Subpart D or Federal CCR Rule). The CCR Rule (following the Part A updates) requires SIGECO to cease discharge of CCR and non-CCR wastestreams into the East Ash Pond as soon as technically feasible, but no later than April 11, 2021, or seek appropriate extensions under 40 CFR § 257.103 to continue operating. As described in this document, SIGECO is requesting an extension of the April 11, 2021 "cease flow" deadline for operation of the East Ash Pond.

For continued operation of the East Ash Pond beyond April 11, 2021, two extension mechanisms are available under the final Part A: (1) *Development of Alternative Capacity is Technically Infeasible* (40 CFR § 257.103(f)(1)) or (2) *Permanent Cessation of a Coal-Fired Boiler(s) by a Date Certain* (40 CFR § 257.103(f)(2)). SIGECO has prepared this document to demonstrate that obtaining alternative capacity for the CCR and non-CCR flows at the F.B. Culley East Ash Pond is infeasible before the April 11, 2021 deadline, and additional time is needed to operate the East Ash Pond until alternative capacity becomes available under the fastest technically feasible timeline.

Eight alternative capacity options were identified and evaluated based on feasibility and schedule including repurposing existing lined facilities, constructing a new pond, constructing a new wastewater treatment facility, and transporting wastestreams to area treatment facilities. Prior to Part A, SIGECO has been actively implementing a plan for redirection of non-CCR to a new lined contact stormwater pond (nearing construction completion) as well as completing dry bottom ash conversion for Unit 3. In addition, SIGECO has determined the construction of an additional new lined CCR-Rule compliant pond for alternative capacity to allow the cessation of CCR flows to the East Ash Pond is the fastest feasible option for obtaining alternative capacity. As described in this demonstration, these ponds will serve both CCR and non-CCR flows currently managed by the East Ash Pond. The combination of these activities (and others described within the demonstration) is believed to represent the fastest feasible timeline for obtaining alternative capacity. Engineering and design associated with these improvements is ongoing, and the systems are expected to be operational on or prior to the requested "cease flow" date of March 1, 2023.

2 Demonstration Purpose and Objectives

This document has been prepared in accordance with the requirements 40 CFR § 257.103(f)(1) to demonstrate that obtaining alternative capacity for CCR and non-CCR flows at the SIGECO F.B. Culley East Ash Pond is infeasible before the April 11, 2021 “cease receipt” deadline provided in 40 CFR § 257.101(a)(1). Accordingly, SIGECO is respectfully requesting an extension to the deadline for East Ash Pond operations pursuant to the Development of Alternative Capacity is Technically Infeasible criteria under 40 CFR § 257.103(f)(1). This document provides the requested information to support this demonstration.

3 Organization of the Demonstration

For ease of review and verification of completeness, this demonstration has been structured consistent with the specific requirements and criteria under 40 CFR § 257.103(f)(1)(iv). The document structure and contents of each section are as follows:

Section 1 – Executive Summary – This section provides an overview of the document.

Section 2 – Demonstration Purpose and Objectives – This section provides a brief discussion of the document purpose.

Section 3 – Organization of the Demonstration – This section provides a discussion of the document outline and organization, indicating where the various regulatory criteria are addressed.

Section 4 – Facility and CCR Unit Background and Description – This section provides background information associated with the generating station, its current operating scenario, and the CCR unit.

Section 5 – Work Plan for Alternative Capacity – This section addresses the requirements for a work plan described in 40 CFR § 257.103(f)(1)(iv)(A), and includes the following key subsections:

- **Section 5.1 – Evaluation of On-site and Off-site Options for Alternative Capacity –** This section provides a detailed Work Plan for obtaining Alternative Capacity consisting of a narrative discussion of options considered, technical infeasibility demonstrations, and a justification of the option selected (40 CFR § 257.103(f)(1)(iv)(A)(1)).

- **Section 5.2 – Detailed Schedule and Narrative Discussion** – This section provides a detailed schedule of the fastest technically feasible time to complete the measures necessary and a narrative discussion describing the schedule and timeline considerations (40 CFR § 257.103(f)(1)(iv)(A)(2 and 3)).

- **Section 5.3 – Progress Toward Alternative Capacity** - This section provides a narrative discussion of the progress made to obtain alternative capacity thus far (40 CFR § 257.103(f)(1)(iv)(A)(4)).

Section 6 – Compliance Certification and Additional Information – This section provides a signed certification that the facility is operating in compliance with this subpart and a summary reference to the requested hydrogeologic and other information (40 CFR § 257.103(f)(1)(iv)(B)). The requested items are provided in appendices.

The recent “A Holistic Approach to Closure Part A: Deadline to Initiate Closure” (Part A) revision to the Federal CCR Rule requires that demonstrations be submitted to EPA for approval no later than November 30, 2020. Following the submission of this demonstration, SIGECO will place a Notice of Intent to apply for a site-specific alternative to initiation of closure due to development of alternative capacity infeasible, along with a copy of the demonstration, into its operating record and onto the SIGECO CCR Compliance web page (https://www.vectren.com/reporting/ccr) as required by 40 CFR § 257.105(i)(14) and 40 CFR § 257.106(i)(14), respectively.

4 Facility and CCR Unit Background and Description

A discussion of the facility, current and future operational scenario, and CCR unit background is provided in the following sections.

4.1 Facility Description and Future Operations

SIGECO owns and operates F.B. Culley located in Warrick County, Indiana, southeast of Newburgh, Indiana (see attached **Figure 1**). F.B. Culley is located along the north bank of the Ohio River, and Little Pigeon Creek is situated along the southeastern-eastern boundary of the facility. Within its operational life, F.B. Culley has operated two (2) CCR surface impoundments referred to as the West Ash Pond and the East Ash Pond (see attached **Figure 2**). However, only the East Ash Pond is currently in operation receiving both CCR and non-CCR wastestreams. The West Ash Pond (described further below) is nearing the completion of closure. Closure of the West Ash Pond is on schedule to be complete by December 17th, 2020.

The East Ash Pond is located in the southeasternmost area of the station and is approximately 10 acres in size. The East Ash Pond was commissioned in approximately 1971 and operates as an unlined CCR impoundment. The East Ash Pond currently receives both CCR and non-CCR flows associated with the operation of two coal-fired generating units: Unit 2 (100 MW) and Unit 3 (287 MW). It should be noted that Unit 1 was previously retired in 2005.

As mentioned above, closure activities for the West Ash Pond are currently underway and nearing completion. As such, neither CCR nor non-CCR flows are currently managed and treated by the West Ash Pond. In order to facilitate closure of the West Ash Pond under the provisions of the Federal CCR Rule, it should be noted that a separate previously-completed project addressed redirection of West Ash Pond flows to the East Ash Pond. Under a closure plan approved by the Indiana Department of Environmental Management (IDEM), a portion of the West Ash Pond is being Closed by Removal (CbR) and a portion of the pond is Closed in Place (CiP) with a final cover system meeting the requirements of the Federal CCR Rule. The CbR portion of the West Ash Pond closure includes construction of a lined Contact Stormwater Pond. As discussed throughout this demonstration, at a future date (July 1, 2021) this lined Contact Stormwater Pond will also manage non-CCR flows currently treated by the East Ash Pond.

A significant amount of planning and engineering is currently underway at F.B. Culley under both the CCR and the ELG rules related to future unit operation and management of flows. There are also a number of current regulatory milestones associated with these efforts. As discussed in the recently issued Integrated Resource Plan (IRP) report, Unit 2 is currently slated for retirement by the end of 2023 and current bottom ash and flue gas desulfurization FGD wastewater streams associated with Unit 2 will cease in conjunction with this unit retirement. It is anticipated that Unit 3 will remain in operation past 2023 and projects are currently underway for dry bottom ash conversion (completed November 2020 prior to the milestone date of December 31, 2020) as well as implementation of a zero-liquid discharge (ZLD) process for management of FGD-related wastewaters (scheduled completion by July 1, 2023). The modification (and associated schedule milestones) for Unit 3 bottom ash transport water (December 31, 2020) is the result of a mandate in the facility's current National Pollutant Discharge Elimination System (NPDES) to cease the discharge of bottom ash transport water no later than December 31, 2020. Additionally, the modifications for the FGD-related wastewaters is the result of a mandate to meet new limits by February 1, 2021, unless the facility commits to retiring Unit 3 or installing a ZLD process, in which case a later compliance date that is no later than December 31, 2023, may be sought. An Order (Cause No. 45052) from the Indiana Utility Regulatory Commission (IURC) was issued on April 24, 2019, in which the IURC authorized the capital expenditure for the ZLD technology on Unit 3 (See **Appendix A**). Issuance of this Order was a necessary step in determining the remaining

useful life of Unit 3 and the consequential management of FGD-related wastewater flow. While engineering associated with implementation of ZLD technology is currently underway, SIGECO is also reviewing potential impacts of the recently published (October 13, 2020) ELG Reconsideration Rule and upcoming 2022 IRP study on the future operation of Unit 3. For this reason and as discussed in this demonstration, additional alternative capacity options are being implemented (representing the fastest technically feasible time) that will also address remaining Unit 3 FGD-related wastewaters while SIGECO evaluates its potential compliance options for Unit 3 under the new ELG Reconsideration Rule. As mentioned previously, non-CCR flows currently managed by the East Ash Pond will be diverted to the new lined Contact Stormwater Pond currently under construction within the footprint of the former West Ash Pond which is nearing completion. Design activities for this non-CCR flow diversion are currently underway and the systems will be operational by July 1, 2021.

4.2 CCR Unit Description

The East Ash Pond was commissioned in approximately 1971 and currently operates as an unlined CCR surface impoundment. Earthen embankments were constructed along the south and east sides of the impoundment. Structural fill from the original construction of the F.B. Culley Generating Station in the 1950s was used to construct the earthen embankment along the east and south sides of the unit, forming the East Ash Pond. The east embankment intersects a natural hillside on the east end of the north side of the impoundment. The perimeter of the embankment is approximately 1,200-feet long, 30-feet high, with exterior side slopes covered with grassy vegetation. The surface area of the impoundment is approximately 9.8 acres and the unit has a normal water operating level of 386 feet above mean sea level (MSL).

Following promulgation of the Federal CCR Rule, SIGECO began working with consultants (AECOM and Haley & Aldrich) to evaluate the East Ash Pond's compliance with the new CCR Rule requirements. The East Ash Pond was certified to be compliant with Federal CCR Rule stability and safety factor criteria. The East Ash Pond is also compliant with the wetlands, fault area, seismic impact zone, and unstable area location restrictions. However, the East Ash Pond did not achieve the uppermost aquifer separation criteria. Groundwater monitoring results associated with the East Ash Pond indicate the data exhibits statistically significant levels (SSLs) of molybdenum and arsenic above Groundwater Protection Standards (GWPS). However, arsenic was subsequently addressed by a successful Alternative Source Demonstration (ASD) (**Appendix H**). Given that the unit is unlined, the East Ash Pond is required to cease CCR and non-CCR flows by April 11, 2021 (under the provisions of the recently effective Part A) and either initiate closure or seek appropriate extensions for continued short-term operation.

4.3 Extension Mechanism Selection

The East Ash Pond will operate beyond April 11, 2021, because no alternative capacity currently exists (either on or off-site) and it is infeasible to obtain alternative capacity prior to the April 11, 2021 "cease flow" deadline. For continued operation of the East Ash Pond beyond April 11, 2021, two extension mechanisms are available under the final Part A: (1) Development of Alternative Capacity is Technically Infeasible (40 CFR § 257.103(f)(1)) or (2) Permanent Cessation of a Coal-Fired Boiler(s) by a Date Certain (40 CFR § 257.103(f)(2)). Key considerations for each of these provisions and the basis for extension selection are outlined below.

1) *Development of Alternative Capacity is Technically Infeasible*: Under this provision, Owner/Operators are required to demonstrate to EPA that obtaining alternative capacity on-site or off-site is infeasible before April 11, 2021, and that additional time is needed to secure additional capacity. In summary, the demonstration must provide information and technical justification that no alternative capacity exists on-site or off-site and must provide a detailed workplan and schedule that includes technical and narrative discussions of how F.B. Culley will obtain alternative capacity. Following public comment and EPA approval, this provision allows for approval of continued operations up to October 15th, 2023 (for non-eligible unlined CCR surface impoundments) or October 15th, 2024 (for eligible unlined CCR surface impoundments). Under the provisions of Part A, the East Ash Pond is a non-eligible unlined CCR surface impoundment.

2) *Permanent Cessation of a Coal-Fired Boiler(s) by a Date Certain*: Under this provision, a CCR unit may continue to receive flows if the owner or operator also commits to coal-fired boiler closure. As discussed in Part A, the facility must commit to coal-fired boiler retirement and cease flows/complete CCR unit closure by October 17th, 2023 (for units less than or equal to 40 acres). Because it is currently anticipated that Unit 3 will continue operation beyond October 17, 2023, F.B. Culley would not qualify for this extension mechanism and it is not discussed further in this demonstration.

Based on the considerations above, SIGECO has prepared this extension based on the requirements for the *Development of Alternative Capacity is Technically Infeasible* extension provision of Part A. As discussed throughout this demonstration, this selection meets the following criteria for *Development of Alternative Capacity is Technical Infeasible* as referenced in 40 CFR § 257.103(f)(1):

- No alternative disposal capacity is available on or off-site (40 CFR § 257.103(f)(1)(i))
- CCR and non-CCR waste streams must continue to be managed in the CCR surface impoundment because it is technically infeasible to complete the measures necessary to obtain alternative disposal capacity either on or off-site of the facility by April 11, 2021 (40 CFR § 257.103(f)(1)(ii)).

5 Work Plan for Alternative Capacity (40 CFR § 257.103(f)(1)(iv)(A)(1))

The Part A demonstration criteria presented in 40 CFR § 257.103(f)(1)(iv)(A)(1) requires a written narrative discussing the options considered both on- and off-site to obtain alternative capacity for each CCR and/or non-CCR waste stream, the technical infeasibility of obtaining alternative capacity prior to April 11, 2021, and the option selection and justification for the alternative capacity selected. The options considered are further discussed in the following sections.

5.1 Evaluation of On-site and Off-site Options for Alternative Capacity

The East Ash Pond has a current storage capacity of 28.2 acre-feet (9,175,000 gallons) and serves a primary role for plant operations with key functions including solids removal by settling and hydraulic surge. The East Ash Pond, as currently operating, receives an average of approximately 1.65 million gallons per day (MGD) of influent from various plant sources. Several of the flows to the East Ash Pond from Units 2 and 3 (such as FGD wastewater-related flows) are comingled. Unit 1 at F.B Culley Station was retired in 2005; however, the basement sump that serves Units 1 & 2 remains in service.

The flowrates of the primary streams are summarized in **Table 1**.

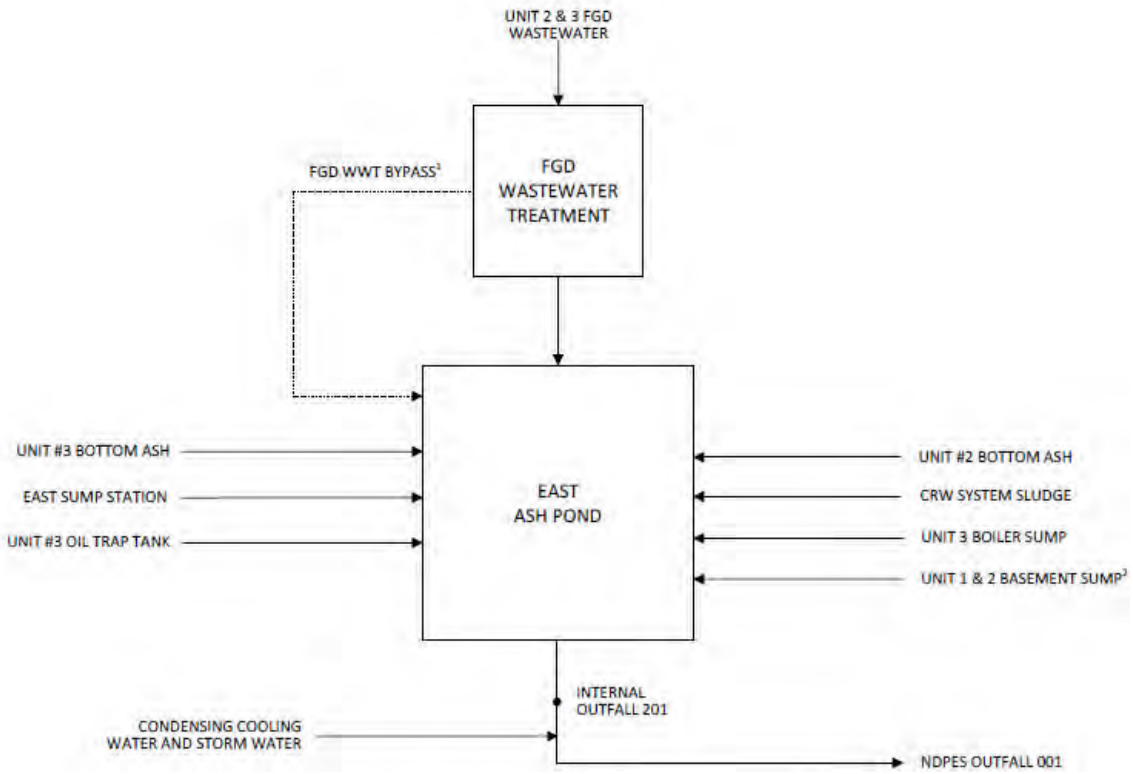
Table 1: East Ash Pond Inflows

CCR Flows			
Source	**MGD**	**Current Management**	**Future Management**
Unit 2 Bottom Ash Sluice Water	0.138	East Ash Pond	New Lined CCR Pond
Unit 3 Bottom Ash Sluice Water	0.321	East Ash Pond	Dry conversion complete 12/31/2020
Unit 2 FGD Wastewater	0.095	East Ash Pond	New Lined CCR Pond
Unit 3 FGD Wastewater			
Non- CCR Flows			
Clarified River Water (CRW) Sludge	0.035	East Ash Pond	New Lined Contact Stormwater Pond
Unit 3 Boiler Sump	0.173	East Ash Pond	New Lined Contact Stormwater Pond
East Sump Station	0.792	East Ash Pond	New Lined Contact Stormwater Pond
Units 1 & 2 Basement Sump	0.088	East Ash Pond	New Lined Contact Stormwater Pond
Mix Tank/ Unit 3 Oil Trap	0.0123	East Ash Pond	New Lined Contact Stormwater Pond
Total	**1.65**		

[1]Note Unit 1 has previously been retired.

The flows into the East Ash Pond are discharged through Internal Outfall 201, then combined with condenser cooling water and stormwater and discharged through NPDES Outfall 001. A block flow diagram of the current flows to and from the East Ash Pond is shown in **Figure 3**.

Figure 3: Flow Diagram of Current Flows to/from East Ash Pond



[1.] FGD Wastewater Treatment (WWT). Bypass for emergency use only. [2.] Note Unit 1 was retired in 2005.

The cessation of CCR and non-CCR flows to the East Ash Pond requires alternative capacity to replace the operational functions of the pond, or the plant must be modified to operate without the East Ash Pond. Primary functions of the East Ash Pond that must be replaced include removal of solids and hydraulic storage. As required by Part A, both on-site and off-site options were evaluated as potential paths to alternative capacity. The following sections detail the options considered and justification for the selected alternative as the fastest feasible timeline for obtaining the needed alternative capacity.

When considering the current operations at the F.B. Culley and the process for obtaining alternative capacity for the East Ash Pond, the following considerations are key:

- **Unit 3 Bottom Ash Flows** – The East Ash Pond has managed Unit 3 Bottom Ash Sluice Water (0.321 MGD). The facility's NPDES permit requires elimination of these flows by December 31, 2020 and a project was completed in November 2020 to convert Unit 3 bottom ash handling operations to a dry handling system using a submerged chain conveyor (SCC). Because this flow has been eliminated prior to the April 11, 2021 "cease flow" deadline, alternative capacity for the Unit 3 Bottom Ash Sluice Water is not discussed further in this report.

- **Unit 2 & 3 FGD-Related CCR Flows** – The current CCR flows to the East Ash Pond include Unit 2 Bottom Ash Sluice Water (0.138 MGD) and Unit 2 and 3 FGD Wastewater (0.095 MGD). The process of obtaining alternative capacity for the non-CCR and Unit 2 & 3 FGD-related wastewater flows is considered "critical path" and the alternative capacity discussions within this report will focus primarily on these flows.

- **Unit 2 Bottom Ash Flows** – The East Ash Pond currently manages Unit 2 bottom ash sluice water at an average flow rate of 0.138 MGD. It is worth noting that the capacity factor for Unit 2 was 15.3% in 2019, 32.1% in 2018, and 22.2% in 2017. Whereas it is anticipated that retirement of Unit 2 will occur by the end of 2023, this flow has also been considered in this evaluation of alternative capacity and fastest feasible timeline. However, feasible options for alternate capacity of this bottom ash stream that can be completed before October 15, 2023 are limited and include only an alternative lined CCR pond or a SCC (similar to that being installed on Unit 3). Complications associated with installation of a SCC for the physical configuration of Unit 2 renders this option technically infeasible in a timeframe less than 36 months. For this reason, this technical evaluation has focused on the critical path of addressing Unit 2 and 3 FGD-related wastewaters. Accordingly, each option has also been given consideration for potential management of the Unit 2 bottom ash wastestream.

The options and process for obtaining alternative capacity for the non-CCR and CCR flows, (FGD-related wastewater flows, and Unit 2 bottom ash flows) is discussed in the following sections.

Non-CCR Flows

Since approximately 2017, efforts have been in place for the redirection of non-CCR flows managed by the East Ash Pond to the lined contact stormwater pond being constructed as part of the West Ash Pond closure activities. These non-CCR wastestreams are summarized in **Table 2**.

Table 2. Redirected East Ash Pond Non-CCR Inflows

Non- CCR Flows		
Source	**MGD**	**Future Management**
Clarified River Water (CRW) Sludge	0.035	New Lined Contact Stormwater Pond
Unit 3 Boiler Sump	0.173	New Lined Contact Stormwater Pond
East Sump Station	0.792	New Lined Contact Stormwater Pond
Unit 1 & 2 Basement Sump[1]	0.088	New Lined Contact Stormwater Pond
Mix Tank/ Unit 3 Oil Trap	0.0123	New Lined Contact Stormwater Pond
Total	**1.100**	

1. Note Unit 1 is retired as of 2005.

Based on commitments to IDEM as part of a variance from a requirement of the 2015 CCR rule (40 CFR 257.101(a)(1)), which is currently still in effect in Indiana, engineering is currently underway and these non-CCR flows to the East Ash Pond are scheduled to cease by July 1, 2021, following construction of infrastructure to redirect these flows to the new lined Contact Stormwater Pond. Re-routing of these non-CCR streams to the new Contact Stormwater Pond was underway well before the final Part A and represents the fastest technically feasible alternative for management of these non-CCR flows.

Unit 2 and 3 FGD-Related Wastewater Stream and Unit 2 Bottom Ash Stream

As mentioned previously, it is SIGECO's current intent to retire Unit 2 by the end of 2023 as discussed in the recent IRP. Nevertheless, Part A requires evaluation of the "fastest technically feasible timeline" for obtaining alternative capacity. For this reason, both Unit 2 and Unit 3 flows managed by the East Ash Pond have been considered in this evaluation of alternative capacity. Considering the current activities for management of non-CCR flows in the new lined Contact Stormwater Pond and dry conversion of Unit 3 bottom ash system, the remaining flows to the East Ash Pond are the FGD wastewater stream from Unit 2 and Unit 3, as well as the Unit 2 bottom ash

wastestream. As mentioned previously, this evaluation focuses on alternatives for management of the Unit 2 and 3 FGD-related wastewaters, but also gives consideration to management of Unit 2 bottom ash flows within each alternative.

Units 2 and 3 are served by a common FGD system producing one wastewater stream discharge to the East Ash Pond. The FGD wastewater discharged to the East Ash Pond is nominally 95,000 gallons per day (GPD). In evaluating alternative capacity options for the FGD wastewater stream, the NPDES permit requirements for this discharge were considered. New numeric effluent limitations for the FGD wastewater discharge take effect in the near future unless the facility commits to retire Unit 3 or proceed with ZLD for FGD-related wastewaters, in which case, a request can be made to modify the NPDES compliance date to not later than December 31, 2023. As SIGECO intends to operate Unit 3 into the future (past December 31, 2023), the focus on obtaining alternative capacity has been directed toward a ZLD system for FGD-related wastewaters. As discussed previously, the receipt of the IURC Order in April 2019, which approved the capital investment, was a necessary step in the process of determining the means of managing the FGD-related wastewater flow. While the order approved the capital expenditure for Unit 3, the future of Unit 2 was subject to the outcome of the required 2019-2020 IRP study and subsequent approvals. Nevertheless, Unit 2 flows have been addressed in this evaluation based on the consideration of ceasing flows to the East Ash Pond and the fastest technically feasible timeline for completing this process.

The following alternative options were considered for the FGD wastewater flows:

1. Alternative 1 – Repurposing Existing Lined Facilities.
2. Alternative 2 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of New Lined Contact Stormwater Pond
3. Alternative 3 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of East Ash Pond
4. Alternative 4 - Alternative Capacity Off-site
5. Alternative 5 – Temporary Wastewater Treatment Facility
6. Alternative 6 – Brine Concentrator
7. Alternative 7 – Membrane Separation
8. Alternative 8 – Wastewater Spray Dryer

Descriptions of each treatment alternative and discussion of feasibility at F.B. Culley are provided in the sections below.

5.1.1 On-site Alternative Capacity – Pond Systems

Alternatives 1, 2, and 3 consider on-site alternatives involving repurposing of existing ponds or construction of a new pond system. These options are discussed further in the following sections.

Alternative 1 – Repurposing Existing Lined Facilities

For completeness in the alternative capacity option development process, consideration was given to repurposing existing lined facilities for management of FGD-related wastewater flows from Unit 2 and 3 and bottom ash flows from Unit 2. The only potential option would be management of these wastewater flows in the new lined Contact Stormwater Pond as no other ponds currently exist on-site. However, several considerations and limitations render this option technically infeasible. First, FGD wastewater flows and the Unit 2 bottom ash flow would be considered a CCR flow and the new lined Contact Stormwater Pond (currently nearing completion of construction and on schedule to be in service by the end of 2020) was not designed for management of CCR flows and would not meet the requirements for a composite liner system under the Federal CCR Rule (40 CFR § 257.72). Significant retrofit of the liner system would be required that would take considerable time and not be achievable by the July 1, 2021 regulatory milestone contained in the IDEM variance for continued use of the East Ash Pond. In addition, this new lined stormwater pond has not been sized for the flows associated with the FGD-related wastewater streams and Unit 2 bottom ash stream. Accommodation of these streams within the new lined Contact Stormwater Pond would require significant expansion to provide the settling capacity required to manage and treat these additional CCR

flows. Further, this new lined Contact Stormwater Pond was included as a component of the IDEM closure plan approval for the West Ash Pond. This option would require both modification of the current closure plan approval for the West Ash Pond (6-month process) as well as an approval from the IDEM Office of Land Quality (OLQ) for operation of a new CCR surface impoundment (12-month process). In addition to these timeline considerations, a CCR compliant monitoring well network would also require installation and monitoring prior to construction/permit approval. For these regulatory and technical reasons, this option is considered technically infeasible within the available timeframe.

Alternative 2 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of New Lined Contact Stormwater Pond

Construction of a new lined CCR Pond (impoundment) in the area to the north of the new lined Contact Stormwater Pond has been evaluated and is the preferred alternative for this analysis as it represents the fastest technically feasible timeframe to obtain alternative capacity and flow cessation to the East Ash Pond. The (CbR) *Excavation Area* of the West Ash Pond closure (area currently complete) has been evaluated as a potential location for a new lined CCR Pond. The new pond would be constructed immediately north of the lined Contact Stormwater Pond that is nearing construction completion and is on schedule to be in service by the end of 2020. In concept, the new lined CCR Pond would be constructed upgradient of and discharge through the lined Contact Stormwater Pond for polishing and flow equalization considerations.

In this proposed area, the CCR materials from the former West Ash Pond footprint have been completely removed and verified, and structural fill has been placed over the excavation grades to create a network of stormwater conveyance channels that manage clean (non-contact) stormwater flows from contributing drainage areas across the plant property. These clean stormwater flows are conveyed through a piping network and ultimately discharged through a NPDES permitted stormwater outfall.

The new lined CCR Pond would be sized for management of FGD-related wastewater flows from Unit 2 and 3 and Bottom Ash discharge flows from Unit 2. Since these flows would be considered CCR flows, the new lined CCR Pond will need to meet the requirements for a composite liner system under the Federal CCR Rule (40 CFR § 257.72) as well as achieve the location restrictions of 40 CFR § 257.60-64. Based on a fatal flaw analysis of these requirements, the potential location (**Figure 4)** is expected to be suitable for construction of a new CCR Rule-compliant surface impoundment.

Figure 4: Potential Location of New CCR Rule-Compliant Pond



As depicted in **Figure 4**, approximately 7 acres of land north of the new lined Contact Stormwater Pond is currently available for a new pond. This would require the clean stormwater flow network to be modified during construction of the new pond in this location. To create an equivalent settling capacity provided by the East Ash Pond, a 7-day retention period is being assumed for the combined Unit 2 bottom ash and Unit 2 and 3 FGD wastewater flows. Since the daily flow is cumulatively 233,000 gallons, approximately 1.63 million gallons (5 acre-feet) of storage is necessary to provide the required settling. To evaluate the sizing requirements for the pond, the volume of a rectangular pond was calculated as follows:

i) This pond was assumed to have the shape of an upside-down rectangular truncated pyramid, with 3:1 H:V (horizontal : vertical) interior side slopes, and a conservative depth of 5 feet that provides a minimum freeboard of 2 feet.

ii) The total area of the pond would be approximately 2 acres and the outer boundary of the pond would be 440 feet by 200 feet, sloping down to a rectangle bottom 410 feet by 170 feet on each side. These dimensions would conservatively provide a total settling volume of approximately 3.10 million gallons (9.5 acre-feet) including freeboard.

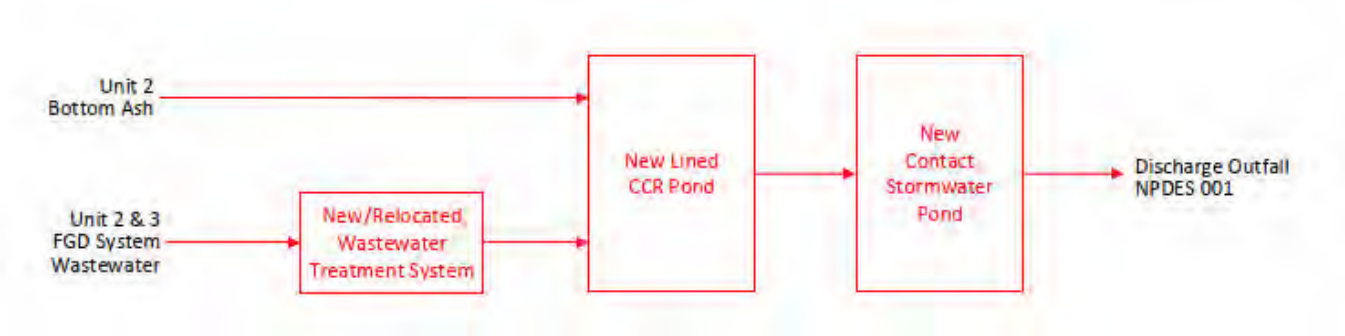
Based on these considerations, construction of a pond of sufficient size to address the CCR flows managed by the East Ash Pond would be technically feasible.

Pursuant to 40 C.F.R. § 257.60(a), new CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must be constructed with a base that is located no less than 1.52 meters (five feet) above

the upper limit of the uppermost aquifer, or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table). Installation of wells to address CCR Rule requirements (as needed) and groundwater monitoring to establish water levels will be conducted to provide a minimum elevation for the base of the future CCR-pond liner system. In the event the water levels prohibit a 1.52 meter separation while maintaining necessary storage capacity, the liner system will be designed in a manner that insures no hydraulic connection between any portion of the base of the unit and the uppermost aquifer.

The existing CCR flows to the East Ash Pond, Unit 2 and 3 FGD wastewater and Unit 2 bottom ash sluice, will be re-routed to the new lined CCR pond. A flow diagram of the new configuration is shown in Figure 5. Modifications of the existing system are shown in red.

Figure 5: Flow Diagram for New Lined CCR Pond



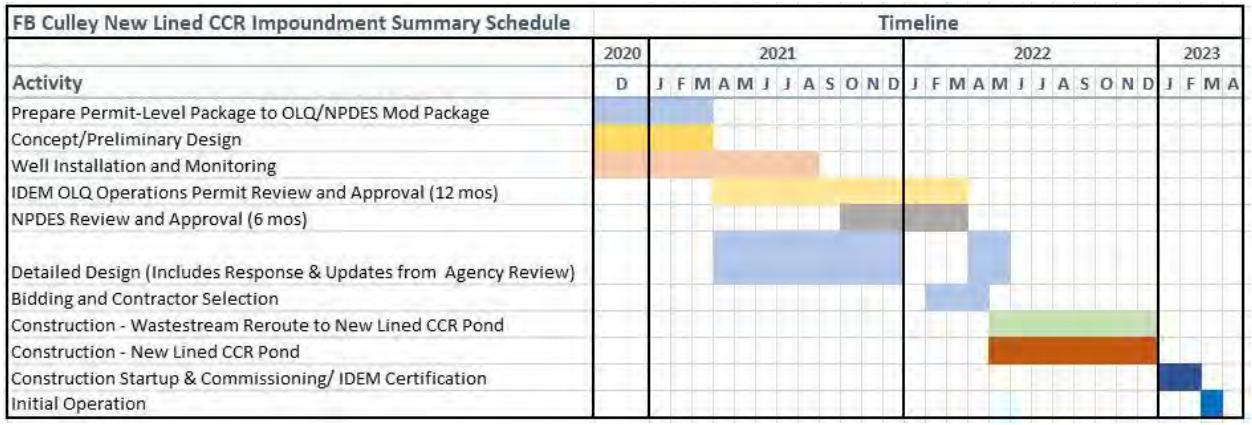
Rerouting of CCR flows from the East Ash Pond requires the design and installation of new transfer lines to the new lined CCR pond and lines from the New Lined CCR pond to the Contact Storm Water Pond, then discharge through permitted Internal Outfall 101 and ultimately through NPDES permitted Outfall 001. The new lined CCR Pond would flow by gravity through the new Contact Stormwater Pond and ultimately discharge through Outfall 001. The existing FGD wastewater treatment system at the East Ash Pond will be replaced or relocated to the new lined CCR Pond area. New electrical and controls infrastructure will be installed at the new lined CCR Pond to support the new equipment and Wastewater Treatment System in this area. To implement this alternative, the following steps would be performed:

- Groundwater Monitoring – Design, Installation, Data Collection and Evaluation
- Conceptual Design
- Preliminary Design
- Permitting - IDEM OLQ Operations Permit and NPDES Major Modification
- Detailed Design
- Engineered Equipment Procurement
  - Pumps
  - Power Distribution Center (PDC), Transformers
  - Distributed Control System (DCS) Integration
- Structural, Mechanical, Electrical and Controls Contractor Bid, Selection and Award
- Structural, Mechanical, Electrical and Controls Construction
  - Reroute of Unit 2 Bottom Ash and FGD wastewater lines to new pond area
  - Installation of new FGD wastewater treatment system
  - Discharge pumping system and ancillary components

    - Electrical, controls and balance of plant (BOP) scope
- Civil Earthworks Contractor Bid, Selection, and Award
- Procurement
- Civil & Earthworks Construction
    - Reroute of clean stormwater conveyance in pond footprint
    - Construct pond embankment
    - Subgrade Preparation
    - Construct composite CCR Pond Liner
    - Construct lines and/or pump stations for flow redirection (concurrently with other features)
    - Provide flow equalization connection between new lined CCR Pond and Contact Stormwater Pond
- Start-up and Commissioning
- Initial Operation

The approximate durations of key activities are summarized in **Figure 6**.

Figure 6. Estimated Simplified Schedule for New CCR Pond in *Excavation Area*



The expected timeframe to complete these efforts is 27 months from December 1, 2020, with an estimated completion date of March 1, 2023. IDEM requires that an operations permit be issued for operation of a new CCR surface impoundment. Based on recent IDEM discussions, they indicated that a 12-month period is the current timeframe for review and issuance of this approval. As such, the schedule includes a 12-month duration for this permit review. Detailed design, equipment procurement and construction not related to civil earthwork for the new lined CCR Pond will be performed concurrent with the OLQ review. Again, Figure 6 represents a simplification of key activities in the overall timeline. For a detailed critical path schedule, schedule see **Appendix C**.

Alternative 3 – Construction of a New On-site CCR Rule-Compliant Pond – Area to North of East Ash Pond

Based on site property availability, construction of a new lined CCR pond in the area north of the East Ash Pond was also considered as part of the options analysis. The potential area north of the East Ash Pond is not currently utilized for plant operations and could be a potential location for such a pond. **Figure 7** below demonstrates the proposed location of the new pond.

The potential area of the new lined CCR pond is not ideal and has steep hill slopes that would require significant earthwork to construct a new pond. The area of the new pond is at an elevation significantly higher than the current East Ash Pond, which would make the re-routing of flows more difficult and would include additional pumps and replacement of existing infrastructure. A proposed pond in this area would also encroach on existing drainage features and potentially require Section 401/404 permitting. Based on recent experience, a Section 401/404 permit can take on the order of one year to obtain. Similar to Alternative 2, this proposed pond would also require an operations permit issued by IDEM OLQ. Considering these complications, a new pond in this proposed area would likely require 36 months to complete, significantly longer than Alternative 2. Based on these considerations, this option is not considered the fastest technically feasible alternative and has been eliminated from consideration.

Figure 7. Potential Location of New On-site CCR Rule-Compliant Pond



5.1.2 Off-site Alternative Capacity

As required by Part A, off-site options for alternative capacity were also considered. Alternative 4 (described below) was developed to address a potential off-site management option.

Alternative 4 –Alternative Capacity Off-site

Alternatives for off-site treatment of the FGD wastewater flow discharged to the East Ash Pond were evaluated. For this alternative, the FGD wastewater would be transported to either a publicly owned treatment works (POTW) or a private facility capable of managing the wastestream. A 10-mile radius from F.B. Culley was surveyed for POTWs or private facilities that may be capable of treating the waste flows. This radius is shown below, overlaid on the area surrounding the station. The POTW of Newburgh, Indiana, is located approximately within this radius, as shown in **Figure 8.**

Figure 8. POTWs Within 10 Miles of F.B. Culley Generating Station



As shown, the Newburgh POTW is the only wastewater treatment facility (WWTF) located within a 10-mile radius. Evansville Eastside POTW is located just outside this radius. The Regional Water Resource Agency's closest plant, Max Rhoads WWTF (serving Owensboro and Daviess County, Kentucky) was also considered as its straight-line distance from the plant is approximately 12 miles. However, due to the road configuration and limited bridges available across the Ohio River, the actual travel distance to the plant is approximately 25 miles one way, and as such, only the Newburgh POTW and Evansville Eastside POTW were examined in detail.

As the closest POTW, a pipeline to convey the FGD wastewater stream to the Newburgh POTW was considered. The straight-line distance for such a pipeline would be approximately 2.2 miles. For transportation via pipeline, this alternative would require several key items to be completed rapidly to be successful:

- Selection of pipeline route would require the completion of any environmental studies and environmental permitting from regulatory agencies.
- Application for any required federal and/or state permitting required, and timely receipt of approval.
- Acquisition of easements for pipeline right of-way.
- Design of pipeline and any necessary pumping stations.
- Construction of pipeline and pumping stations.
- Final testing.

Given the length of pipeline required and the significant regulatory and design obstacles, construction of a pipeline to a POTW is not the fastest technically feasible alternative. This alternative would require longer than 36 months to complete the route evaluation, permitting, design, property access rights, and construction of such a pipeline.

This timeline would exceed that of Alternative 2 and would not represent the fastest technically feasible alternative. This option would also come with significant schedule risks in the event property access could not be obtained

Transportation of FGD wastewater flows via truck was also considered. The FGD wastewater flow accounts for 95,000 GPD that would need to be transported to an off-site facility for treatment. Assuming a truck capacity of 5,000 gallons, 19 truckloads would be needed daily to transfer FGD wastewater to the off-site WWTF. Although truck transport of this quantity of wastewater is feasible, the nearby Newburgh POTW facility cannot accept truck delivery of wastewater. Further, several of the facilities contacted place limitations on the total suspended solids (TSS) in the wastestreams they can accept. The city of Evansville limits raw wastestreams to 2,114 milligrams/Liter (mg/L), which is substantially lower than the wastestreams currently discharged to the East Ash Pond. Pretreatment to reduce the TSS is required before treatment can be considered by any of the POTWs contacted. In addition to limitations on TSS, POTWs are not equipped to treat the constituents in FGD wastewater.

Many, if not all, of their processes are incompatible with treatment of the CCR wastewater flows from F.B. Culley. The existing Newburgh POTW consists of an activated sludge system with eight (8) sequencing batch reactors followed by ultraviolet disinfection. The system is designed to remove TSS, biological oxygen demand (BOD), and pathogens prior to discharging to the Ohio River. Additional treatment steps would likely be required to remove dissolved metals to below applicable categorical and local standards.

The requirement to pretreat FGD flows removes any benefit of managing this wastestream off-site. In addition, this option would not address the Unit 2 bottom ash wastestream as significant solids removal (in settling tanks for similar facilities) would be required prior to transport of the material. Given the additional infrastructure required for off-site management and treatment of the FGD wastewater flows, completion of this project is not considered to be technically feasible prior to October 15, 2023 and does not represent the fastest technically feasible alternative.

5.1.3 On-Site Wastewater Treatment Facility Alternatives

The FGD wastewater stream must meet the effluent limitations as defined by the current NPDES permit for F.B. Culley. The F.B. Culley NPDES permit contains a reopening clause that allows the facility to request a compliance date that is no later than December 31, 2023 for the Unit 3 FGD wastestream if unit retirement or ZLD technology is pursued. In 2017, various options to comply with the NPDES permit were evaluated including ZLD and advanced wastewater treatment. A ZLD technology that would eliminate the FGD wastewater stream was selected. The selection of the ZLD technology was included in a filing to the IURC seeking approval for the capital expenditure. The Order granting approval was issued April 24, 2019. The ZLD technology selected is detailed in Alternative 8.

Alternative 5 – Temporary Wastewater Treatment Facility (WWTF)

A temporary WWTF to treat the FGD wastewater stream was also considered. To replace the operational functions of the East Ash Pond, the temporary WWTF requires a significant amount of storage capacity and the capability to remove and dewater the suspended solids in these waste streams. The WWTF consists of the following primary components:

- Equalization Storage Tanks - to receive and store the influent flows.
- Primary Dewatering Clarifier/Thickeners - to remove suspended solids from the liquid.
- Filter Feed Storage Tanks – to receive the clarifier/thickener underflow and store until fed to the secondary dewatering filter presses.
- Secondary Dewatering Filter Presses - to remove liquid from the solids so that they can be disposed in a landfill.
- Treated Water Storage Tanks - to store the water that is returned to the system or discharged.

Equalization tanks balance the flow to the downstream clarifiers and blend the wastestreams to reduce fluctuations in temperature and composition. The equalization tanks are sized for 24 hours of wastestream production to

address upset conditions in the WWTF and influent peak flow events such as stormwater runoff. The 0.233 MGD of CCR flow requires 250,000 gallons of capacity in the equalization tanks. The system would have 2 tanks, each 30' in diameter and 30' in height with mixers to prevent the solids from settling.

From the equalization tanks, the untreated wastestreams will be transferred to one of two clarifier/thickeners. Clarifier/thickeners is a large quiescent circular tank that removes the suspended solids by settlement. For these streams, each clarifier is approximately 110' diameter by 15' high. The large clarifier/thickeners volume is required to provide the 10 days of residence time required for the wastewater treatment reagents added to remove the mercury from the FGD wastewater. A coagulant and polymer are also added to the feed stream to promote settling and produce a low suspended solids stream. A rotating rake assembly moves the settled solids to the center of the clarifier/thickeners where they are discharged to the filter feed storage tanks. The overflow from the clarifier/thickeners is collected in a sump and pumped to one of the treated water storage tanks. Any water discharged must meet the TSS requirements and mercury limitations of the NPDES permit.

The treated water tanks would store the water for re-use by the system. Return water pumps would send water back to the system for re-use for bottom ash transport, fly ash transport and FGD system make-up. The treated water tanks would be sized for 250,000 gallons of capacity in 2 tanks. Each tank would be approximately 30' in diameter by 30' height and an agitator would not be required.

The filter press is a batch operation. Because solids must be purged from the clarifier/thickeners on a continuous basis, filter feed storage tanks are required. Filter press performance is highly dependent on the characteristics of the solids. Fly ash and FGD solids are among the more difficult to dewater and a filter press cycle time of 3 to 8 hours is expected for this material. To accommodate batch operation, 150,000 gallons of filter feed storage capacity is required. Due to the higher solids content, 2 tanks of 75,000 gallons, approximately 24' x 24' each, would be installed.

The filter press units would be fed from the filter feed tank with high-pressure diaphragm pumps. The fill cycle for a filter press varies dependent on the characteristics of the material. Based on the throughput, 2 or more filter press units are required. Dewatered solids would drop from the filter press units to the roll away bin and be taken to a landfill. The filtrate would be collected and returned to the clarifier/thickeners. Solids that are disposed in the landfill must meet the requirements for free liquids.

The project scope for this WWTF includes field-erected tanks, engineered equipment, structural steel, buildings, piping, electrical, and controls. A significant amount of engineering design is required including:

- Major Engineered Equipment – The system included the following engineered equipment: pumps, agitators, clarifiers, filter presses, power distribution systems, and distributed control systems. The design and manufacturing duration for this equipment ranges from 6 – 12 months after receipt of order.

- Foundations – The WWTF has 6 tanks ranging in size from 75,000 to 250,000 gallons. Each tank will require deep foundations, typically 30' to 60' piles, a mat and containment walls. The 2 clarifier/thickeners, each 110' in diameter also require deep foundations. The filter press unit must be elevated to discharge to the bins these structural support members and enclosure will also require deep foundations.

- Field Erected Tanks – The tanks would all be knockdown field erected. Panel sections would be fabricated, then assembled in the field.

- Electrical and Controls - The new WWTF will require a new electrical service for the pumps, agitators, clarifiers, filter press, freeze protection, heating, ventilation and lighting. New instrumentation and controls are required to operate this system.

In addition to the WWTF, the existing wastestreams must be re-directed from the East Ash Pond to the new facility. New pipe runs are required, and the existing systems will require upgrade and modification to transport these wastestreams to the new WWTF.

The following table summarizes the fastest schedule for implementation of a WWTF to treat the wastestream flows to the East Ash Pond.

Table 3. Temporary Wastewater Treatment Facility Implementation Schedule

Activity	Estimated Duration
Conceptual Design and Investigations	3 months
Major Equipment Vendor Selection and Award	2 months
Detailed Design	12 months
Construction Contractor Selection and Award	2 months
Construction	18 months
Start-up and Commissioning	3 months
Initial Operation	2 months
Total	**42 months**

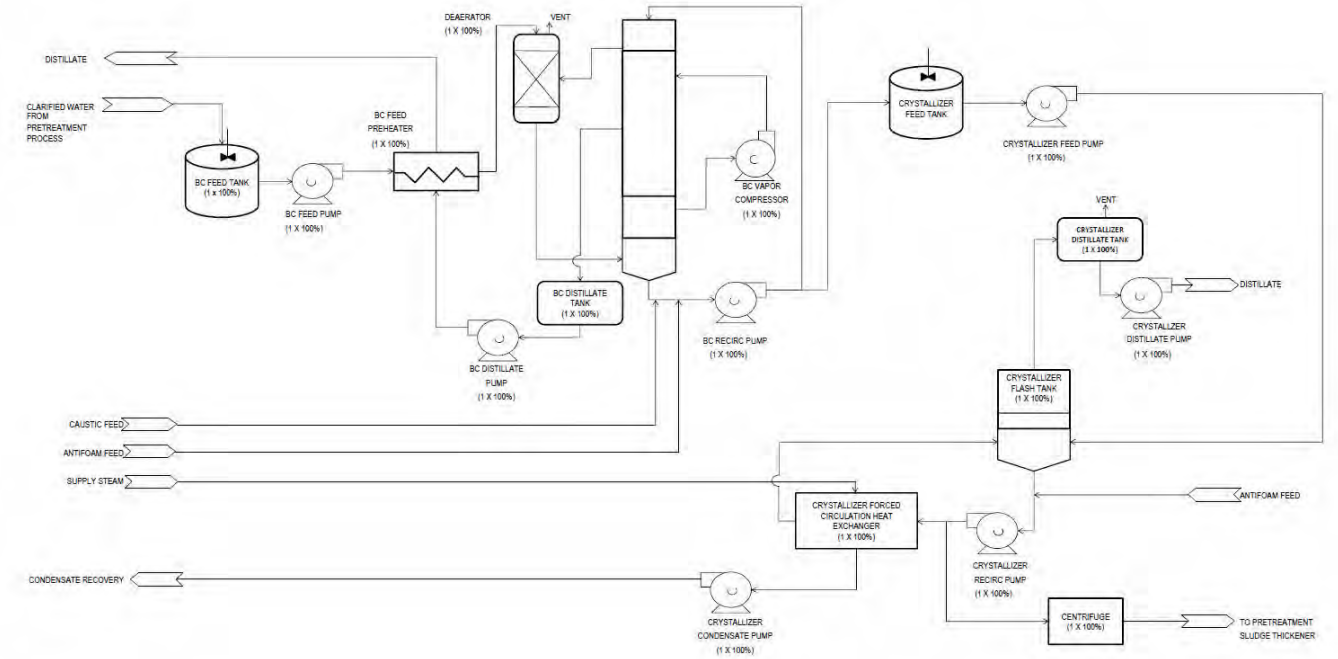
The fastest feasible duration to construct a WWTF is 42 months from December 1, 2020. The estimated completion for the system is June 1, 2024 and significantly exceeds the timeframe of the fastest technically feasible alternative.

Alternative 6 – Brine Concentrator

A brine concentrator / crystallizer is a ZLD technology. The system is a thermal process that concentrates dissolved species in a brine sludge that is then solidified in the crystallizer unit. Crystallized solids (salts) can then be disposed in a landfill. For an FGD wastewater application, pretreatment steps are required to 'soften' the wastewater prior to thermal treatment to reduce scaling and a reduction in throughput. The softened wastewater is then thermally treated in the brine concentrator or encapsulated with fly ash and lime. Evaporated water, now free of dissolved solids, is collected and returned to the plant as makeup water.

The materials of construction for the brine concentrator and crystallizer must be resistant to corrosion due to the high concentrations of chloride and elevated temperatures associated with the process. As a result, fabrication of the equipment has a long duration and requires over 12 months to procure. Brine concentrator and crystallizer for the FGD wastewater was not the selected option due to reliability issues in comparison with other ZLD options. Total project duration to design, procure, and install a brine concentrator is 36 to 42 months. A schematic of the brine concentration and crystallization steps was prepared by Black and Veatch and is presented as **Figure 9**. While potentially feasible, this option was not selected as the preferred option could be implemented in a shorter timeframe. In addition, this option is limited in that it would not address Unit 2 bottom ash flows.

Figure 9: Brine Concentrator / Crystallizer Schematic



Alternative 7 – Membrane Separation

Membrane separation is also a ZLD technology for treating FGD wastewater. This technology is typically used in conjunction with encapsulation to produce a waste product that can be landfilled. In a reverse osmosis system, a pump is used to convey a high-pressure stream of FGD wastewater across a polymeric membrane. The FGD wastewater salts are concentrated on one side of the membrane while a clean permeate (product stream) stream is discharged from the opposite side. The permeate can be returned to the FGD system as makeup water (ZLD) or discharged. The concentrated brine stream can be blended with fly ash and/or lime and landfilled. Membrane systems require pre-treatment of the wastewater to remove suspended solids and reduce scaling potential. Upstream pre-treatment typically includes clarification, sand filters, cartridge filters, anti-scalant additives, anti-microbial additives, and pH adjustment.

There is limited experience within the utility industry applying membrane separation for the treatment of FGD wastewater. This is an emerging technology and is not expected to be ready for commercial application for several more years. In consideration of the uncertainties regarding long term performance and reliability, and extended duration for project implementation, membrane technology is a technically infeasible alternative. In addition, this option is also limited in that it would not address Unit 2 bottom ash wastestream.

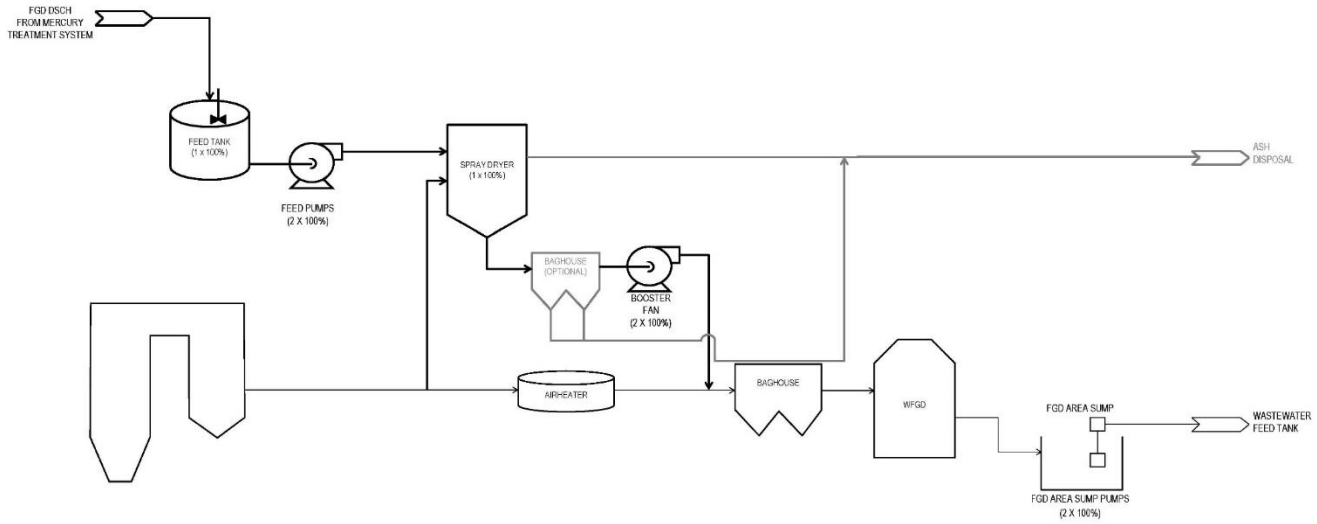
Alternative 8 – Wastewater Spray Dryer

A wastewater spray dryer evaporator (SDE) system uses a slip stream of hot flue gas to evaporate a wastewater upstream of a particulate collection device. Solids and salts in the wastewater are atomized and dried in the spray dryer vessel. The flue gas can either be returned to bulk flue gas stream where the solids are removed with the fly ash or routed to a separate particulate collector prior to being returned with the bulk flue gas. A preliminary process flow diagram of a wastewater spray dryer system is provided in **Figure 10**.

While waste spray dryer technology has only been recently applied to FGD wastewater, it is based on established technology in a similar application. An estimated duration of 33 months is required to design, procure and install a wastewater spray dryer system. While this alternative continues to be pursued for continued operation of Unit 3 beyond the NPDES compliance date of December 31, 2023, the timetable for completion of this option exceeds

that of Alternative 2 and is not considered the fastest technically feasible alternative. It also has the limitation of not addressing Unit 2 bottom ash flows.

Figure 10: SDE Process Flow Diagram



5.1.4 Alternative Selected and Analysis of the Site and any Site-Specific Conditions that Led to the Alternative Selected (40 CFR § 257.103(f)(1)(iv)(A)(1)(i))

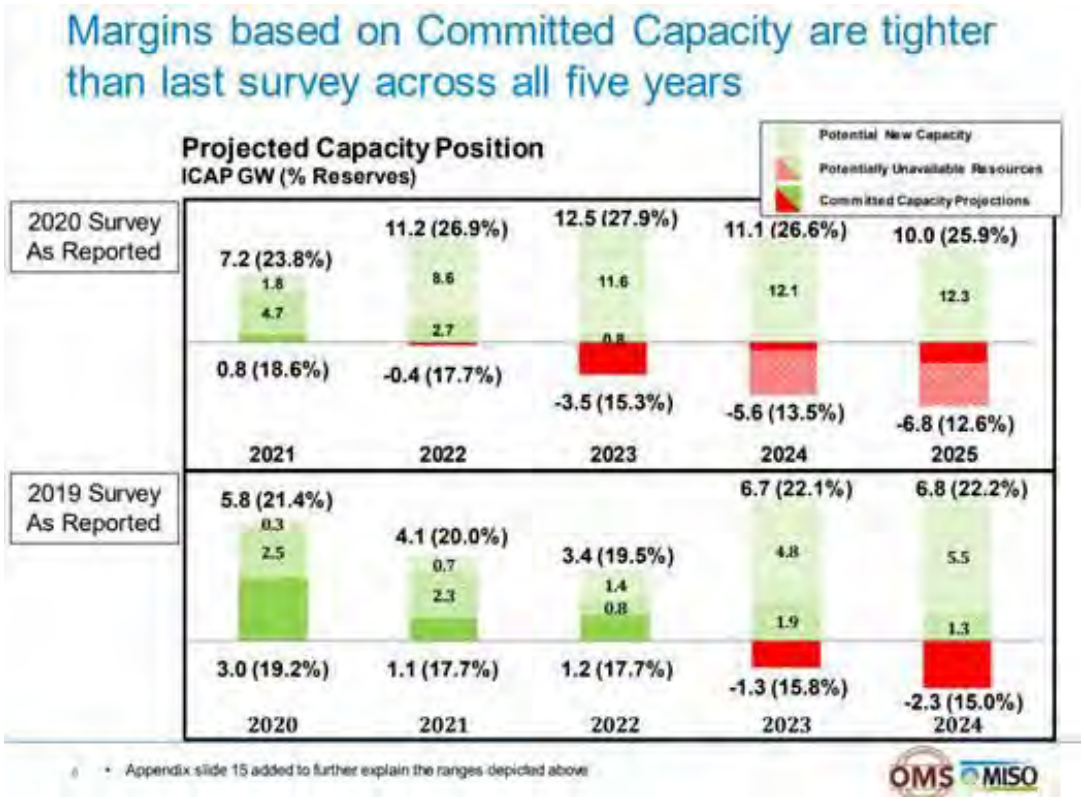
Alternative 2 (new lined CCR Pond) has been selected based on the following site-specific and other considerations:

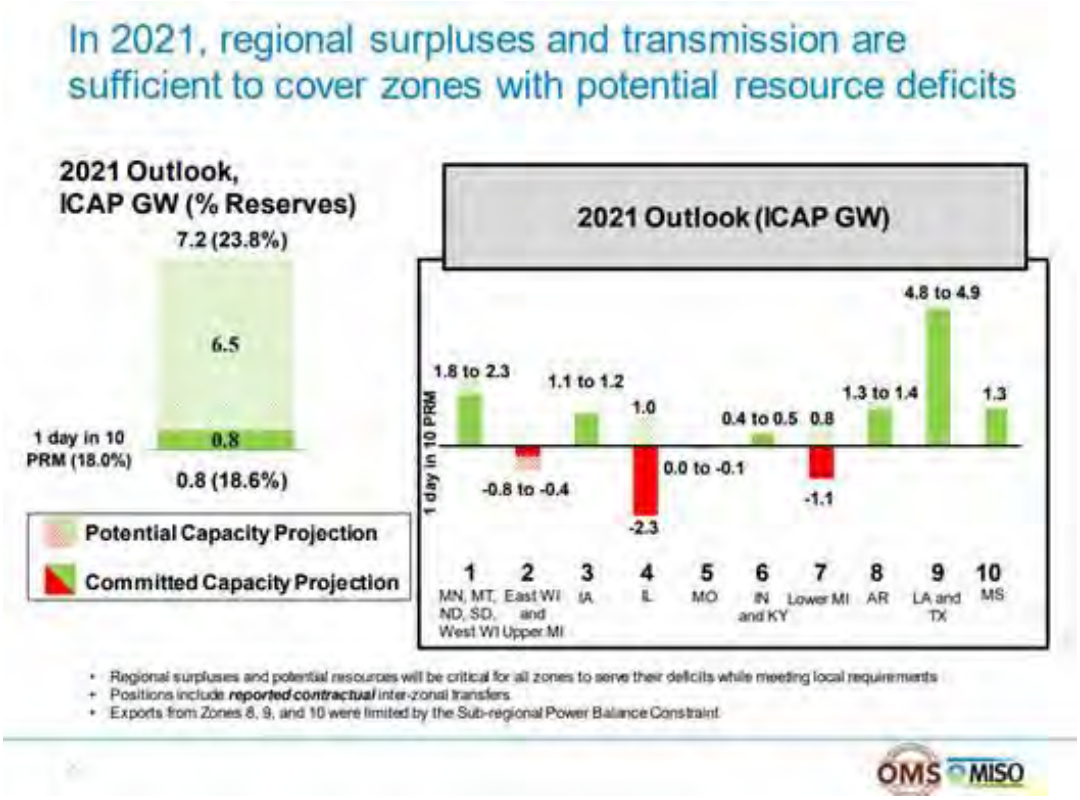
- Alternative 2 represents the “fastest technically feasible timeline” for addressing remaining flows to the East Ash Pond,
- The area selected for the new lined CCR Pond is well known (geotechnical characteristics, groundwater levels, etc.) and is ideal for construction of a new pond system,
- Alternative 2 involves reroute of flows, but does not involve significant mechanical or other treatment-related systems with longer lead times and startup/operational challenges, and
- Alternative 2 is well understood and defined, and has a high level of construction schedule certainty.

5.1.5 Adverse Impact on Plant Operation if the East Ash Pond Were No Longer Available (40 CFR § 257.103(f)(1)(iv)(A)(1)(ii))

Given the lack of current alternative capacity, continued operation of Units 2 and 3 at F.B. Culley is wholly dependent on the continued operation of the East Ash Pond until alternative capacity can be obtained for all flows managed by the East Ash Pond under Alternative 2 (March 1, 2023). If the CCR and non-CCR flows to the East Ash Pond were to cease on April 11, 2021, without alternative capacity available, Units 2 and 3 will not be able to continue operation.

F.B. Culley Units 2 and 3 have a combined capacity of 387 MW and currently comprise 27 percent of SIGECO’s generating units. F.B. Culley Units 2 and 3 are an essential part of the generation capacity within the fleet and the region. The results of the 2020 MISO Organization of MISO states survey projects a slight capacity surplus for zone 6 in 2021 and a potential shortfall in 2025. The survey shows that the MISO system in its entirety could experience a shortfall as early as 2022.





The source for the charts shown above:
https://cdn.misoenergy.org/20200708%20RASC%20Item%2004a%202021%20OMS-MISO%20Survey456786.pdf

5.1.6 Explanation and Justification for the Amount of Time being Requested and How it is the Fastest Technically Feasible Time to Complete the Development of Alternative Capacity

Based on this evaluation, the fastest technically feasible option for obtaining alternative capacity is a new lined CCR Pond in the vicinity of the new lined Contact Stormwater Pond (Alternative 2). This alternative supplements current plant activities to reduce flows to the East Ash Pond (i.e., dry bottom ash conversion of Unit 3 and management of non-CCR flows in the new lined Contact Stormwater Pond). With construction of a new lined CCR Pond, all flows to the East Ash Pond can cease on or before March 1, 2023. In addition, this option provides for significant flexibility in the event of operational and/or future generation changes. While ZLD technology consisting of a SDE system has been selected and continues to be pursued for addressing NPDES and Effluent Limitation Guideline (ELG) regulatory considerations relating to Unit 3 FGD flows, this project (if completed) would result in a cease flow date after Alternative 2 and is not considered the "fastest technically feasible timeline" for ceasing flows to the East Ash Pond. The selected alternative (Alternative 2) for management of non-CCR and future closure-related flows represents the fastest technically feasible time to obtain alternative capacity for these flows.

5.2 Detailed Schedule and Narrative Discussion (40 CFR § 257.103(f)(1)(iv)(A)(2) and (3))

The provisions of 40 CFR § 257.103(f)(1)(iv)(A)(2) and (3) require that a detailed schedule be provided illustrating the fastest technically feasible time to complete the measures necessary for alternative capacity to be available including a visual timeline representation. The visual timeline must clearly show the following:

- How each phase and the steps within that phase interact with or are dependent on each other and the other phases (40 CFR §257.103(f)(1)(iv)(A)(2)(i)),
- Steps and phases that can be completed concurrently (40 CFR §257.103(f)(1)(iv)(A)(2)(ii)),
- Total time needed to obtain the alternative capacity and how long each phase and step within each phase will take (40 CFR §257.103(f)(1)(iv)(A)(2)(iii)), and
- At a minimum, the following phases: engineering and design, contractor selection, equipment fabrication and delivery, construction and start-up and implementation (40 CFR §257.103(f)(1)(iv)(A)(2)(iv)).

In addition, 40 CFR §257.103(f)(1)(iv)(A)(3) requires a narrative discussion of the schedule and visual timeline representation which must discuss all of the following:

- Why the length of time for each phase and step is needed and a discussion of the tasks that occur during the specific step (40 CFR §257.103(f)(1)(iv)(A)(3)(i)),
- Why each phase and step shown on the chart must happen in the order it is occurring (40 CFR §257.103(f)(1)(iv)(A)(3)(ii)),
- The task that occur during each of the steps within the phase (40 CFR §257.103(f)(1)(iv)(A)(3)(iii)), and
- Anticipated worker schedules ((40 CFR §257.103(f)(1)(iv)(A)(3)(iv)).

These items are provided and discussed in the following sections.

5.2.1 Regulatory and Other Considerations Associated with Overall Project Schedule

The scenario at F.B. Culley involves a series of interrelated regulatory and technical milestones. In order to address the requirements of this section, two detailed schedule representations have been provided. The first, provided in **Appendix B**, provides a representation of the overall schedule for F.B. Culley, which includes sections for the regulatory process to select future generation technology, CCR-related activities, and alternative pond capacity development activities. This schedule is intended to represent the overall scenario at F.B. Culley and illustrates the interrelationships of the various activities.

5.2.2 Design and Installation Schedule

The cessation of CCR and non-CCR flows to the East Ash Pond requires alternative capacity to replace these functions. Based on current construction schedules, the East Ash Pond will be required to manage non-CCR flows until the new lined Contact Stormwater Pond is complete and operational (by end of 2020) and non-CCR flows can be re-routed (by July 1, 2021 under current IDEM OLQ commitments). Unit 3 Bottom Ash flow will be eliminated no later than December 31, 2020 (NPDES requirement). FGD wastewater and Unit 2 bottom ash streams will be redirected to a new lined CCR Pond (Alternative) which will be constructed adjacent to the new Contact Stormwater Pond. Based on the implementation schedules discussed within this document, this new lined CCR pond will be complete and operational on or before March 1, 2023.

Essentially, the approach selected to obtain alternative capacity has the following three subprojects:

- **Unit 3 Boiler Bottom Ash Handling System Wet to Dry Conversion – Submerged Chain Conveyor**

Unit 3 Bottom Ash flow will be eliminated from the East Ash Pond by the end of November, which is before the NPDES permit required date of December 31, 2020, when the new SCC system is completed and functional.

- **Closure of West Ash Pond / New Lined Contact Stormwater Pond and Re-Routing of Non-CCR Waste Piping**

Based on current construction schedules, the East Ash Pond will be required to manage non-CCR flows until the contact stormwater pond is complete and operational, which is on schedule to be completed by the end of 2020. At that time, physical construction work to re-route non-CCR flows from the East Ash Pond to the new contact stormwater pond can begin, with a scheduled completion date of no later than by July 1, 2021. Detailed design for re-routing these flows began in July of 2020 and is expected to last 6 months in duration. Following completion of design activities, a 3-month contractor bidding and selection period will occur, with an expected contract award date by end of February 2021. Construction is expected to take 4 months in duration, which includes 2 weeks for start-up and commissioning followed by initial operation of 2 weeks prior to cessation of flow for non-CCR streams to the East Ash Pond by July 1, 2021. A schedule for key milestone activities is found in **Table 4**.

Table 4: Milestone Activities for Re-routing Non-CCR Flows

MILESTONE ACTIVITY	DATE
Design Team Site Visit	6/24/2020
Receipt of 60% Design Documents	10/14/2020
Receipt of 90% Design Documents / Issue Bid Package	12/9/2020
Award Construction Project	2/28/2021
Project Completion/ Cease Flow of Non-CCR Streams to East Ash Pond	7/1/2021

- **New Lined CCR Pond and Re-Routing of CCR Piping**

The selected alternative (Alternative 2) will require 27 months for conceptual and preliminary design, permitting, detailed design, vendor and contractor selection, equipment fabrication, construction and start-up and commissioning. In consideration of the overall process leading to cessation of flows (both CCR and non-CCR) to the East Ash Pond, this effort is considered critical path. Below is a detailed discussion of the anticipated schedule for implementation.

The project schedule for the selected alternative can be broken down to the following segments:

a. Conceptual and Preliminary Design
b. Permitting
c. Detailed Design
d. Equipment Procurement and Manufacture
e. Construction Bid and Award
f. Construction
g. Construction Certification / Start-up and Commissioning
h. Initial Operation

5.2.2.1 Conceptual and Preliminary Design

Work on this phase for alternative capacity will initiate in December 2020 with project kick-off and the beginning-of-project definition and preliminary design. This phase will include various field investigations and infrastructure and information gathering to support the preliminary design and operating permit application. Groundwater monitoring wells will be installed to address CCR Rule requirements (as needed) and establish the groundwater water levels to provide a minimum elevation for the base of the future CCR Pond liner system. Groundwater monitoring data from existing wells will also be considered in order to provide a complete assessment in the fastest feasible timeframe. Key deliverables from this phase include:

a. Design Basis
b. Plant Water Balances and Process Flow Diagrams
c. Overall Site Plan
d. Install Groundwater Monitoring Wells
e. Preliminary Pond Design Drawings and Specifications
f. Permit Application Package
g. Permit Applications (i.e. IDEM OLQ Submittal and NPDES Major Modification)
h. Cost Estimate
i. Detailed Project Schedule

The new lined CCR Pond will be sized based on the expected flows. An ideal candidate location has been identified in the area to the north of the new lined Contact Stormwater Pond. A key objective of the preliminary design phase is to develop the permit package for submittal to IDEM OLQ. This task along with the installation of groundwater monitoring wells are on the critical path.

Other objectives of this phase include detailed information of the CCR streams that discharge to the East Ash Pond. This includes verification of the flowrates, composition, temperature, pressure and operating requirements. Activities to gather this information may include flow measurements, sampling and analysis, review of plant operating data and the collection of design information. Once all the streams have been defined and characterized, a conceptual design will be developed to redirect the flows to the new lined CCR pond. This may include the modification of existing plant facilities, re-grading to redirect stormwater and new facilities to transport the flows to the new lined CCR Pond. Four months are planned for the conceptual design phase.

The scope for the preliminary design phase will be refined based on the results of the conceptual design. Potential design issues and the information needed will be established. Development of the preliminary design will follow the conceptual design. This phase is expected to be completed in 4 months.

5.2.2.2 Permitting

A number of permitting requirements are associated with the selected alternative for alternative capacity. The two primary required permits are summarized below:

1. CCR Surface Impoundment Operations Permit from IDEM OLQ – Indiana is very involved in the surface impoundment operations approval and closure approval process as surface impoundments are regulated

by the state as land disposal units and Indiana has adopted reference to the Federal CCR Rule within their state regulations (329 IAC 10). While approval is not required for construction of a CCR surface impoundment, approval by IDEM OLQ is required for operation of a CCR surface impoundment. This process consists of submission of design materials, flows, and associated calculations and analyses. SIGECO representatives recently contacted IDEM to discuss the review time for this CCR surface impoundment operations approval, and IDEM indicated that 365 days (from submission) is the typical timeframe for approval. This review period has been factored into project schedules and will involve preparation of a permit-level design package for IDEM review and approval early in the design process (first four months), and detailed design will be continued during IDEM review of this package. During the review process, the permit-level design package will need to be supplemented with data demonstrating compliance with the aquifer separation criteria of 40 CFR 257.60.

- While the CCR Surface Impoundments Operations Permitting process is occurring, SIGECO will also be working with IDEM to obtain approval for the construction of the pond in this specific location, in accordance with requirement A2 of the "Approval of Closure/Post-Closure Plan F.B. Culley West Ash Pond" issued by IDEM, dated December 20, 2019. Requirement A2 states, "The owner or operator must request approval from IDEM before modifying the approved closure/post-closure requirements and procedures."

2. NPDES Major Modification – In order to address the proposed CCR flow treatment changes, a Major Modification of F.B. Culley's NPDES permit will be required. Based on recent IDEM experience and discussions with IDEM, 6 months is required from package submission to approval. Again, this has been factored into the schedule and this activity occurs in parallel with other activities (such as detailed design and OLQ review of the CCR surface impoundment application). It should be noted that there is schedule float associated with this permit approval process, and it can lag in schedule by approximately 6 months if needed without affecting the overall project timeline.

There will be a number of other approvals required such as permit coverage for Stormwater Associated with Construction Activities (Rule 5 in Indiana). However, these are typically shorter lead time permits and are not near the critical path.

Finally, it should be noted that the permitting timelines assume a Section 401/404 permit will not be required. This is a reasonable assumption given that new fill was just placed in the proposed CCR Pond area and it appears no stream crossings or tree clearing will be required for the construction activities of the CCR Pond or associated piping systems.

5.2.2.3 Detailed Design

The detailed design phase will commence following the conceptual and preliminary design and will occur in parallel to IDEM permit reviews. The key objective of the detailed design phase is to develop a design package and specifications for the equipment procurement and construction packages. Work from the conceptual and preliminary design will be used to develop drawings and specifications. Key deliverables from this phase include:

a) Final Pond Site Plan, Sections and Details Drawings
b) Final Pond Grading Plans and Calculations (geotechnical, stormwater management, pond capacity, etc.)
c) Liner and Earthwork Specifications
d) Piping and Instrument Diagrams (P&IDs)
e) General Arrangements (GA's)
f) Pipe Routing and Lists
g) Electrical One Lines, Circuit Drawings, Cable Routing Drawings, Schedules
h) Control System Logic, Input Output Lists, Connection Diagrams
i) Construction and Equipment Specifications

Detailed design will be executed concurrently with on-going groundwater monitoring activities and permitting support. The pond design will not be finalized until all required design approvals have been received and permitting

authorities have completed their reviews. Design tasks associated with the redirected flows from the East Pond include hydraulic calculations, pipe support design, electrical and control cable routing and termination diagrams, electrical load studies and control logic development. It may be necessary to proceed with the procurement of specific engineered equipment to achieve schedule milestones. This information may include electrical and controls circuits diagrams and equipment interface connections. A total of 10 months is planned for detailed engineering and design. During this phase, Issue for Bid (IFB) packages will be completed. Issue for Construction (IFC) packages will be developed following contractor award and completion of review/approval by the permitting authorities.

5.2.2.4 Equipment Procurement and Manufacture

Mechanical Engineered procurements are expected to include pumps or pump upgrades. A duration of 1 month is expected to receive vendor bids with 2 months to evaluate and award each package. Based on previously solicited vendor bids for similar equipment pumps are expected to have a 6-month lead time after receipt of order (ARO) for manufacturing and delivery, resulting in a total duration of 9 months for mechanical procurements.

Electrical procurements are expected to include transformers, motor control centers (MCC), power distribution centers (PDCs), and distributed control system components. As with the mechanical procurements, a duration of 1 month is expected to receive vendor bids and a 2-month period for evaluation and vendor award. The long lead items associated with electrical procurements have been identified as the PDCs with an expected lead time of 9 months ARO for manufacturing and delivery, resulting in a total duration of 12 months for mechanical procurements.

Mechanical and Electrical procurements occur in parallel for a total procurement cycle of 12 months. These activities follow completion of the mechanical detailed design and runs in parallel with completion of the electrical detailed design. The manufacturing and delivery of these components will occur in parallel with construction of the new pond. Other procurements are piping, structural steel, pond liner, valves and instrumentation. These items have been identified to have a short lead time and will be purchased by the construction contractor. They do not impact the overall project schedule and will occur in parallel with the mechanical and electrical procurements.

5.2.2.5 Contractor Bid, Selection and Award

In this phase, a Request for Proposal (RFP) will be issued to contractors to construct the system. The project scope may be bid and awarded in 2 separate packages:

- Package 1 - mechanical, structural, electrical and control scope that is not associated with the pond
- Package 2 - civil earthworks associated with the new CCR Pond

The decision to award the construction in 1 or 2 packages will be based on achieving the shortest duration for construction.

The bid, selection, and award phase is expected to take 3 months from issuance of the RFP. This includes 1.5 months for the bidders to prepare proposals and 1.5 months for evaluation and contract negotiations. Evaluation of the proposals includes a review of the means and methods of construction proposed by the bidders and any alternates that may improve the design or reduce the project schedule. The duration of the evaluation period is dependent on the quality of the proposals received, responsiveness of the bidders to questions, and complexity of the alternates considered. These activities occur concurrently with completion of detailed design and equipment fabrication and delivery.

5.2.2.6 Construction and Start-Up

The candidate location for the new lined CCR Pond is the CbR *Excavation Area* of the West Ash Pond closure (area currently complete). The CCR materials from the former West Ash Pond footprint have been completely removed and verified, and structural fill has been placed over the excavation grades to create a network of stormwater conveyance channels that manage clean (non-contact) stormwater flows from contributing drainage

areas across the plant property. The new pond will meet the requirements for a composite liner system under the Federal CCR Rule (40 CFR § 257.72) as well as the location restrictions of 40 CFR § 257.60-64. The successful completion of groundwater monitoring and completion of review by the regulatory agencies is required before the pond design can be finalized.

The available area for the new lined CCR pond is 7 acres. Construction is planned to require 8 months including site prep and cleaning, cut and fill, and liner installation.

The project scope will include modifications to reroute various wastestreams to the new pond. The two CCR wastestreams are pumped by transfer systems. New lines will be routed to the pond using existing pipe racks and chases where available. The existing system treating the FGD wastewater prior to discharge to the East Ash Pond will be replaced or relocated to an area adjacent to the new lined CCR Pond. Tie-ins for the electrical supply and other utilities must be planned and coordinated with plant operations and it may be necessary to perform this work during an outage. An overall duration of 8 months is planned for construction of the new lined CCR Pond and rerouting the CCR lines from the East Ash Pond.

Following completion of construction, the system will undergo start-up and commissioning. This project phase will require 2 months and involves instrument loop checks, motor meggering, electrical system settings, overall system hydrostatic testing, mechanical operation of all rotating equipment and various other tasks to prepare the system for operation. Issues discovered during this period may require support from the equipment vendor to repair or replace damaged components. At the conclusion of this phase, a package with all checkout records will be produced.

Following the above and prior to operation, the pond construction must be certified to IDEM by a registered engineer. Certification requires record drawings of the final construction and various records verifying the installed pond meets the required standards. Two months is planned for assembly of this packet and IDEM review and release for operation.

A period of 1 month is allocated for initial operation, during which the process controls loops will be tuned and setpoints adjusted. A key objective of the run-in period is to verify the reliability of the system over a range of operating conditions. Issues that are identified during this phase may require support from the equipment vendor or modification of the system. At the completion of the initial operation period, all CCR flows to the East Ash Pond will cease and be redirected to the new pond.

5.2.2.7 Schedule Summary

Based on the schedule provided in **Appendix C**, conceptual design activities for the new lined CCR Pond and redirection of flows are currently underway. The path to alternative capacity will involve preliminary design, contractor selection, detailed design, procurement and construction. Based on this schedule, it is currently anticipated that flows to the East Ash Pond will cease on March 1, 2023. Throughout the design process, project management efforts will be made to identify schedule improvements.

5.2.2.8 Anticipated Worker Schedules (40 CFR 257.103(f)(1)((iv)(A)(3)(iv)

During construction of the new lined CCR Pond and infrastructure to redirect flows, the anticipated worker schedules will consist of 50-hour weeks. This will involve working 5 days per week, approximately 10 hours per day. If weather or other delays are encountered, the worker schedule may be adjusted (increased) to address this lost time and maintain project schedules.

5.3 Progress Toward Alternate Capacity (40 CFR 257.103(f)(1)(iv)(A)(4))

Part A (40 CFR 257.103(f)(1)(iv)(A)(4) requires a narrative discussion of the progress the Owner/Operator has made to obtain alternative capacity for the CCR and/or non-CCR wastestreams. The narrative must discuss all the steps taken, starting from when the Owner/Operator initiated the design phase up to the steps occurring when the

demonstration is being compiled. It must discuss where the facility currently is on the timeline and the efforts that are currently being undertaken to development alternative capacity.

An Environmental Compliance review for continued coal-fired operation at F.B. Culley was performed in 2019 and a Final Report issued in February 2020. The review encompassed the modifications required to comply with the final CCR Rule and ELG Rule and the proposed revisions. Recommendations for modifications to the plant were made in the report and have been summarized in this Work Plan. Summary of projects in progress is as follows:

- Construction of the new lined Contact Stormwater Pond is underway and expected to be completed by December 31, 2020. This pond will serve non-CCR flows currently being sent to the East Ash Pond beginning on or before July 1, 2021 (following flow redirection).

- Re-route of contact stormwater flows from the East Ash Pond to the new Contact Stormwater Pond is underway and expected to be completed by July 1, 2021.

- Design of the Unit 3 dry bottom ash system has been completed (initiated early 2018) and installation of the unit is complete as of November, 2020. (prior to the December 31, 2020 deadline in accordance with NPDES permit requirements). This effort has eliminated this flow to the East Ash Pond.

- Efforts have been initiated for fatal flaw evaluation and conceptual design of a new CCR Rule compliant surface impoundment in the vicinity of the new lined Contact Stormwater Pond and redirection of subject flows to this pond. As discussed in this document, this pond will serve CCR-flows that are currently managed by the East Ash Pond (Unit 2 Bottom Ash, Unit 2/3 FGD Wastewater-related flows). Once complete on or before March 1, 2023, operation of this new CCR Pond will result in cessation of all flows to the East Ash Pond.

- Study work and planning for the FGD Wastewater system has been ongoing since 2017. The early study work and planning included efforts to evaluate the potential for reducing flow volumes and meeting the constituent requirements of the FGD wastewater in order to determine whether the design requirements for a spray dryer system could be achieved. The selection of the ZLD technology was included in a filing to the IURC seeking approval for the capital expenditure. The order granting this approval was issued April 24, 2019. Planning and preparation for design initiation has been occurring throughout 2020 culminating in Owner's Engineer vendor selection in August 2020. Equipment specifications, vendor selection, and BOP design activities for the FGD Wastewater system began in September 2020. This effort is scheduled to be completed on July 1, 2023 (after initiation of the new CCR Pond operation). In the event this activity can be completed prior to operation of the new CCR Pond, this will result in early elimination of this flow to the East Ash Pond. However, due to the fact this project is not the fastest technically feasible timeline, ZLD technology is secondary to the new CCR Pond construction.

6 Compliance Certification and Additional Information (40 CFR § 257.103(f)(1)(iv)(B))

In accordance with *40 CFR § 257.103 (f)(1)(iv)(B),* the following information and attachments are submitted to demonstrate that the F.B. Culley Generating Station is in compliance with 40 CFR § 257 Subpart D – Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments (CCR Rule).

In accordance with Federal CCR Rule requirements, groundwater monitoring wells were installed to evaluate the groundwater quality in the vicinity of the East Ash Pond and the West Ash Pond. The analytical results and subsequent ASD efforts (**Appendix H**) resulted in the identification of one constituent, molybdenum, at an SSL exceeding the Appendix IV GWPS at the East Ash Pond and the identification of two constituents, lithium and molybdenum, at an SSL exceeding the Appendix IV GWPS at the West Ash Pond. In response, Haley & Aldrich prepared a Corrective Measures Assessment (**Appendix J**) for the East Ash Pond. The Corrective Measures Assessment for the East Ash Pond evaluated the risk related to the molybdenum exceedances and determined there are “no adverse effects on human health or ecological receptors…” from groundwater at the East Ash Pond. The Corrective Measures Assessment for the West Ash Pond was initiated and is currently in progress. Semiannual groundwater sampling has been implemented to continue to monitor and evaluate groundwater and will continue through the closure and post-closure processes at each unit. Activities toward remedy selection are ongoing for the East Ash Pond and will be pursued for the West Ash Pond following completion of the Corrective Measures Assessment.

With respect to groundwater considerations, it should further be noted that the alternative capacity being pursued at F.B. Culley as discussed throughout this demonstration will result in closure of the East Ash Pond sooner than originally anticipated. The West Ash Pond closure design resulted in the excavation of nearly all of the CCR material in potential contract with groundwater. A small quantity of CCR may be in contact with groundwater during periods of prolonged wet weather and/or high river levels.

Compliance data required by Part A associated with the East Ash Pond is referenced in the sections below and provided in Appendices to this report. Supplemental data and information related to the West Ash Pond is included in an addendum to this report (**West Ash Pond Supplemental Attachments).**

6.1. Certification of Compliance

The F.B. Culley Generating Station is in compliance with the requirements of the CCR Rule. SIGECO manages the company website for the F.B. Culley Generating Station and it is kept up to date and contains all the necessary documentation. **Appendix D** includes the required certification of compliance.

6.2. Visual Representation of Hydrogeologic Information

6.2.1. Groundwater Monitoring Well Locations

Figures detailing the location of the groundwater monitoring wells in relation to the East Ash Pond at F.B. Culley are attached (**Appendix E**). Figures detailing the location of the groundwater monitoring wells in relation to the West Ash Pond at F.B. Culley are included in the addendum (**West Ash Pond Supplemental Attachments**). The figures were prepared by Haley & Aldrich.

6.2.2. Well Construction Diagrams

Well construction diagrams and boring logs including stratigraphic cross-sections for the East Ash Pond are attached (**Appendix F**). Well construction diagrams and boring logs including stratigraphic cross-sections for the West Ash Pond are included in the addendum (**West Ash Pond Supplemental Attachments**). The well construction diagrams were prepared by Haley & Aldrich.

6.2.3. Groundwater Flow Direction

Figures detailing the groundwater elevation contours of November 2016 and June 2017 for the East Ash Pond to account for seasonal variations are attached (**Appendix G**). Figures illustrating the groundwater elevation contours of April 2017, January 2018, April to August 2018, and December 2018, for the West Ash Pond are included in the addendum (**West Ash Pond Supplemental Attachments**) The figures were prepared by Haley & Aldrich.

6.3. Groundwater Monitoring Analytical Results

Tables summarizing the constituent concentrations of each groundwater monitoring well sampled at the East Ash Pond between 2016 and 2020 are attached (**Appendix H**). The January 2020 Groundwater Monitoring Reports (prepared by Haley & Aldrich) including the ASD efforts are also included in **Appendix H**. Tables summarizing the constituent concentrations of each groundwater monitoring well sampled at the West Ash Pond between 2019 and 2020 are included in the addendum (**West Ash Pond Supplemental Attachments**). The tables were prepared by Haley & Aldrich.

6.4. Description of Site Hydrogeology

A description of the site hydrogeology at the F.B. Culley Generating Station is attached (**Appendix I**). The description was prepared by Haley & Aldrich.

6.5. Corrective Measures Assessment

The corrective measures assessment report for the East Ash Pond is attached (**Appendix J)**. The report was prepared by Haley & Aldrich. The corrective measures assessment report is located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Ash-Pond-Corrective-Measures-Assessment-Report.pdf)

Groundwater sampling at the East Ash Pond identified one Appendix IV constituent, molybdenum, in exceedance of GWPS, and the Corrective Measures Assessment was implemented in response to these results. The Corrective Measures Assessment evaluated the potential risk the constituent posed and potential corrective measures to prevent further releases. Groundwater flow was evaluated and found to be radial with an overall flow direction from the upland areas north of the Ash Pond to the South. As discussed in the Corrective Measures Assessment, "Groundwater downgradient of the East Ash Pond is not used as a source of drinking water and is not flowing toward any groundwater supply wells." The risk assessment also demonstrated "no adverse effects on human or ecological health from groundwater uses resulting from coal ash management practices at the F.B. Culley Generating Station East Ash Pond". Potential corrective measures to prevent further releases were identified and evaluated. These measures include Monitored Natural Attenuation, Hydraulic Containment, and In-Situ Treatment. These evaluations are further discussed and compared in the Corrective Measures Assessment.

The West Ash Pond is currently undergoing the corrective measures assessment. The Notification of Initiation of Corrective Measures Assessment is included in the addendum (**West Ash Pond Supplemental Attachments)** and is located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-West-Notification-of-Initiation-of-Corrective-Measures-2020.pdf)).

6.6. Progress Reports

The progress reports on corrective action remedy dated March 2020 and September 2020 are attached (**Appendix K**). The reports were prepared by Haley & Aldrich and are also located on the company CCR compliance webpage for the F.B. Culley facility.

March 2020 Report (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Ash-Pond-Semi-Annual-Selection-of-Remedy-Progress-Report_2020March.pdf)

September 2020 Report (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Ash-Pond-Semi-Annual-Selection-of-Remedy-Progress-Report_2020September.pdf)

The West Ash Pond is currently undergoing the corrective measures assessment; therefore, progress reports for the West Ash Pond have not been prepared as of the date of this report.

6.7. Structural Stability Assessment

The structural stability assessment report for the East Ash Pond is attached (**Appendix L**). The report was prepared by AECOM. The report is also located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Structural-Stability.pdf)

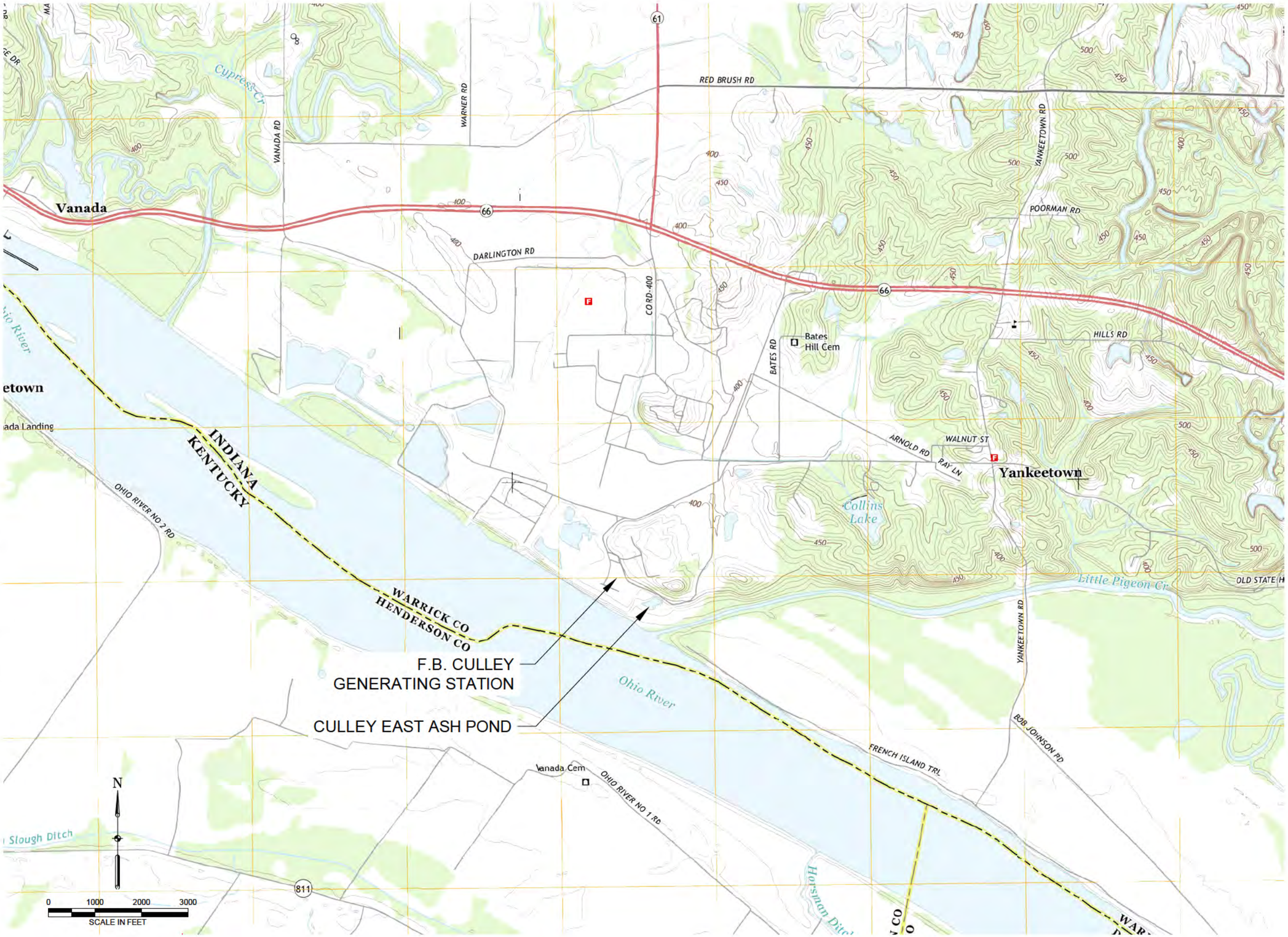
The structural stability assessment report for the West Ash Pond is not required as the unit was classified as "inactive" under the original 2015 CCR rule and was in the process of closure when the "Direct Final Rule" constituting a vacatur of 40 CFR §257.100 became effective.

6.8. Safety Factor Assessment

The factor of safety assessment report for the East Ash Pond is attached (**Appendix M**). The report was prepared by AECOM. The report is also located on F.B. Culley's company website. (https://www.vectren.com/assets/downloads/planning/ccr/Culley-East-Safety-Factor-Assessment.pdfThe factor of safety assessment report for the West Ash Pond is not required as the unit was classified as "inactive" under the original 2015 CCR rule and was in the process of closure when the "Direct Final Rule" constituting a vacatur of 40 CFR §257.100 became effective.

Figures

CARUSO, MICHAEL, 10/7/2016 3:12 PM



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F.B. CULLEY
GENERATING STATION
NEWBURGH, IN

DEVELOPMENT OF
ALTERNATIVE
CAPACITY
INFEASIBLE
DEMOSTRATION

ISSUED FOR CERTIFICATION

	DATE	BY
ISSUED FOR BIDDING		
ISSUED FOR CONSTRUCTION		

REVISIONS

NO.	DESCRIPTION	DATE
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△		
△		
△		
△		

AECOM PROJECT NO:	60442676
DRAWN BY:	MJC
DESIGNED BY:	MJC
CHECKED BY:	TLE
DATE CREATED:	8/18/2016
PLOT DATE:	4/22/2016
SCALE:	AS SHOWN
ACAD VER:	2014

SHEET TITLE

LOCATION MAP

FIGURE 1

AECOM DRAWING PATH: P:\Projects\Environmental\60442676_VectrenCCR\7.0_CAD_GIS\7.04_Plan_Sheets\CULLEY-LOCATION MAP.dwg



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DEVELOPMENT OF ALTERNATIVE CAPACITY INFEASIBLE DEMONSTRATION

ISSUED FOR CERTIFICATION

	DATE	BY
ISSUED FOR BIDDING	-	-
ISSUED FOR CONSTRUCTION		

REVISIONS

NO.	DESCRIPTION	DATE
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AECOM PROJECT NO:	60442676
DRAWN BY:	JMW
DESIGNED BY:	JMW
CHECKED BY:	RJB
DATE CREATED:	12/19/2018
PLOT DATE:	12/19/2018
SCALE:	AS SHOWN
ACAD VER:	CIVIL 3D 2018

SHEET TITLE

SITE MAP

N

0 200 400 600
GRAPHIC SCALE (IN FEET)

FIGURE 2

Appendices

Appendix A
IURC Order in Cause No. 45052

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) APPROVAL OF ASSOCIATED RATEMAKING AND ACCOUNTING TREATMENT; (3) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COMPLIANCE PROJECTS TO MEET FEDERALLY MANDATED REQUIREMENTS ("CULLEY 3 COMPLIANCE PROJECT"); (4) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CULLEY 3 COMPLIANCE PROJECTS THROUGH VECTREN SOUTH'S ENVIRONMENTAL COST ADJUSTMENT MECHANISM; (5) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION, TAX AND FINANCING COSTS ON THE CULLEY 3 COMPLIANCE PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE CCGT AND CULLEY 3 COMPLIANCE PROJECT UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; (6) ONGOING REVIEW OF THE CCGT; (7) AUTHORITY TO IMPLEMENT A PERIODIC RATE ADJUSTMENT MECHANISM FOR RECOVERY OF COSTS DEFERRED IN ACCORDANCE WITH THE ORDER IN CAUSE NO. 44446; AND (8) AUTHORITY TO ESTABLISH DEPRECIATION RATES FOR THE CCGT AND CULLEY 3 COMPLIANCE PROJECT ALL UNDER IND. CODE §§ 8-1-2-6.7, 8-1-2-23, 8-1-8.4-1 *ET SEQ*, 8-1-8.5-1 *ET SEQ.*, AND 8-1-8.8 - 1 *ET SEQ.*	)	CAUSE NO. 45052 APPROVED: APR 24 2019

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On February 20, 2018, Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") filed its verified petition in this Cause seeking, among other relief, certificates of public convenience and necessity for a new duct-fired F-class 2x1 combined cycle gas turbine ("CCGT") providing 700 MW of baseload and 150 MW of peaking capacity pursuant to Ind. Code ch. 8-1-8.5 and for certain environmental projects at its Culley Unit 3 generating station pursuant to Ind. Code ch. 8-1-8.4. Petitions to intervene were filed by the Vectren Industrial Group; Valley Watch, Inc., the Citizens Action Coalition of Indiana, Inc., and the Sierra Club ("Joint Intervenors"); the Indiana Coal Council, Inc. ("ICC"), Sunrise Coal, and Alliance Coal, LLC (the "Coal Parties"); SABIC Innovative Plastics Mt. Vernon, LLC; St. Joseph Energy Center, LLP; St. Joseph Phase II LLC; and Evansville Western Railway. All of these petitions to intervene were subsequently granted. A public field hearing was held in Evansville on July 11, 2018, at which time members of the public presented testimony. The Indiana Utility Regulatory Commission ("Commission") held an evidentiary hearing at 9:30 a.m. on October 9, 2018, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana.

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

1. **Notice and Jurisdiction.** Notice of the hearings in this Cause was given and published as required by law. Vectren South is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Vectren South is subject to the jurisdiction of this Commission in the manner and to the extent provided by Indiana law. Pursuant to Ind. Code chs. 8-1-8.5 and 8-1-8.4, Vectren South may seek Commission approval of Certificates of Public Convenience and Necessity. Accordingly, the Commission has jurisdiction over Vectren South and the subject matter of this proceeding.

2. **Vectren South's Characteristics.** Vectren South is an operating public utility incorporated under the laws of the State of Indiana, with its principal office and place of business in the City of Evansville. Vectren South provides electric and gas utility service to the public in Indiana and is subject to the regulation by this Commission in the manner and to the extent provided by the laws of the State of Indiana. This proceeding pertains to Vectren South's electric utility business. Vectren South renders retail electric utility service to approximately 145,000 customers in seven counties in southwestern Indiana, and owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power for residential, commercial, industrial and municipal uses. Vectren South furnishes such electric utility service to retail customers located in Vanderburgh, Posey, Gibson, Pike, Warrick, Dubois and Spencer Counties, with a major portion of such customers residing in and around the City of Evansville, Indiana. Vectren South owns and operates 1,248 megawatts ("MW") of total net generating capacity. This generation capacity is primarily derived from the following five coal-fired baseload units providing a total of approximately 1,000 MW: A.B. Brown 1 (245 MW), A.B. Brown 2 (245 MW), F.B. Culley 2 (90 MW), F.B. Culley 3 (270 MW) and Warrick Unit 4 (150 MW[1]). Vectren South procures 100% of its coal supply from mines located in Indiana.

[1] Represents Vectren South's ½ interest in Warrick Unit 4, a 300 MW unit.

Vectren South's operations are subject to federal, state and local rules promulgated and/or implemented by, among others, the federal Environmental Protection Agency ("EPA"), the Indiana Department of Environmental Management ("IDEM") and by the Environmental Rules Board of the State of Indiana. Such rules establish environmental compliance standards that govern emissions and discharges from Vectren South's electric generating units.

3. Overview of the Evidence.

A. Condition of Current Fleet.

i. Vectren South. The main drivers behind Vectren South's proposal are the age and operating characteristics of Vectren South's existing baseload capacity and the upcoming deadlines for significant capital investments to address environmental regulations. Mr. Wayne D. Games, Vice President of Power Supply at Vectren South, testified regarding the condition of Vectren South's current generation fleet and the challenges facing the fleet. He testified Vectren South's fleet consists of five coal-fired baseload units totaling 1,000 MW. Mr. Games further testified that growth of renewable energy sources and low natural gas prices have negatively affected MISO's dispatch of Vectren South's coal-fired units. Instead of running continuously, Vectren South's units are now cycled up and down throughout the day, or are shut down altogether, decreasing unit efficiency and increasing wear and tear on the units. Mr. Games testified that because the units were not designed to cycle in this manner, the units cannot effectively compete with gas units in particular, which have far better operating flexibility. Continued market reforms are exacerbating this issue and jeopardizing unit availability and reliability.

Mr. Games also explained that the individual units face additional operating challenges. In particular, the A.B. Brown Units rely on scrubbers that utilize a technology that has been abandoned by the industry because of its high variable costs and the vapor it emits which causes corrosion of the unit structure. The scrubbers are already past their expected 30 year design life and present a significant risk to reliability and maintenance costs. He explained that Culley Unit 2 is Vectren South's oldest and smallest unit and that it has the worst heat rate of any coal unit in the state. Finally, he explained the unique circumstances related to the joint operation of the Warrick Unit which creates uncertainty as to the duration of its operation.

Ms. Angila Retherford, Vice President of Environmental Affairs and Corporate Sustainability, testified regarding two new major federal regulatory initiatives – Effluent Limitations Guidelines ("ELG") and Coal Combustion Residuals ("CCR") - impacting Vectren South's coal-generating units. Absent substantial investment at all of Vectren South's coal plants, they must cease operations by December 31, 2023. Ms. Retherford described Vectren South's environmental compliance strategy for the A.B. Brown and Culley units and testified future compliance costs were modeled in Vectren South's 2016 Integrated Resource Plan ("IRP") under the business as usual scenario. Ms. Retherford testified these rules and other existing federal regulatory requirements will require Vectren South to make significant further investment at the A.B. Brown and Culley generating facilities to continue their operation.

ii. Non-Utility Parties.

(1) OUCC. OUCC witnesses Lauren M. Aguilar – Utility Analyst, Anthony A. Alvarez – Utility Analyst and Peter M. Boerger – Senior Utility Analyst testified regarding Vectren South's request for a CPCN to construct the CCGT. These OUCC witnesses testified Vectren South's decision to construct the CCGT is premature because Vectren South has not explored all practical alternatives to extend the life of the A.B. Brown units. OUCC Witness Aguilar ultimately recommended that the decision to build the CCGT be delayed until the end of the 2019 IRP process, in order to allow Vectren South the opportunity to evaluate additional alternatives. The OUCC offered no alternative resource proposal, but argued for a "blended approach" with the possible continued use of existing assets, and suggested that the necessary expenditures to continue use of these assets could be viewed as buying an "option on the future." The OUCC witnesses asserted that deferring any decision until the conclusion of the 2019 IRP process would still allow sufficient time to take action without affecting reliability.

(2) Coal Parties. The Coal Parties' witnesses generally testified that Vectren South should wait to transition its baseload generation from coal to natural gas because the environmental regulations driving the transition, the ELG and CCR rules, are in flux and not yet final. Specifically, the Coal Parties' witnesses testified that recent and anticipated EPA reconsiderations of the ELG and CCR regulations, as well as the potential stay or replacement of the Clean Power Plan ("CPP"), create the potential scenario where Vectren South could operate the A.B. Brown and Culley units beyond 2023 without the need to make material investments in compliance measures. Coal Parties witness Michael J. Nasi – Partner with the law firm of Jackson Walker L.L.P. – further testified that Vectren South's decision to retire its coal plants is premature. He recommended that the decision be delayed until the environmental regulations driving the decision are better understood. With respect to the A.B. Brown units, the Coal Parties suggested that Vectren should investigate an alternative scrubber technology marketed by a Chinese firm to replace the existing dual alkali scrubbers. This technology which uses ammonia creates material that can be sold as fertilizer with revenues used to offset variable operating costs of the scrubber.

iii. Vectren South Rebuttal. Ms. Retherford, who is also a licensed attorney, testified regarding the risks associated with continuing to operate Vectren South's coal-fired fleet and delaying the decision to construct the proposed CCGT. Ms. Retherford testified that recent legal developments related to the CCR rule have made it impossible for Vectren South to continue operating its coal-fired fleet beyond 2023 without significant capital investment. She testified that the current water discharge permits require, and the groundwater monitoring results at the A.B. Brown and Culley ash ponds confirm, that Vectren South must cease discharging coal ash by December 31, 2023, pursuant to the ELG and CCR rules. She also testified that *Utility Solid Waste Activities Group v. Environmental Protection Agency*, 901 F.3d 414 (D.C. Cir. 2018), 2018 U.S. App. LEXIS 23547, confirms that the CCR Rule is final, including the final compliance deadlines at issue in this proceeding. Ms. Retherford testified that pond retirement delay is not an option, and therefore Vectren South must either make investments to comply with the CCR rule or retire the plants before 2024.

In response to the Coal Parties' position that the current administration could alleviate environmental carbon regulations applicable to the coal units, Ms. Retherford testified that the Administration's proposed replacement for CPP does not alleviate the problems. On August 31, 2018, the EPA published its proposed Affordable Clean Energy ("ACE") rule in lieu of CPP. She explained

that ACE would increase uncertainty and could actually increase the cost of compliance. For units with high heat rates – such as A.B. Brown – ACE would cause significant future compliance costs.

Vectren South also presented the testimony of Richard McMahon from Edison Electric Institute ("EEI") regarding the growing importance of Environmental, Sustainability and Governance ("ESG") reporting and metrics to the financial community, and the focus of all public electric utilities on being responsive to these topics and establishing explicit carbon reduction targets as part of their public disclosures. Mr. McMahon described the coordinated electric industry response to the demands for ESG reporting, and provided specific examples of lenders and large institutional investors who are putting pressure on companies to transition from dependence on coal units. He explained that Vectren South's 60% carbon emission reduction was in line with similar targets publicly disclosed by its electric utility peers. He also presented information regarding the industry transition from reliance on coal to use of gas as part of the ability to reduce carbon emissions.

As to the potential for alternative scrubbers, Vectren South witness Paul Farber – Principal of P. Farber & Associates, LLC – testified regarding the shortcomings of the technologies presented by Sunrise Coal witness Dombrowski and OUCC witness Aguilar and explained why, from an operational and financial perspective, it would not be prudent for Vectren South to adopt those technologies. With respect to the ammonia based scrubber technology presented by witness Dombrowski, Mr. Farber testified the technology has very limited deployment in the United States and would present a number of operational challenges if installed at baseload coal-fired units like A.B. Brown. These uncertainties and risks posed by adoption of this technology include its cost, its impact on operation of the units (including that it might cause Vectren South to be out of compliance with regulations for other constituents such as mercury and particulate matter absent further types of investments), the unknown ability to sell fertilizer output, and the complications associated with dealing with vendors with no domestic history. He discussed in depth the substantial operational burden and health and Homeland Security risk associated with handling the large amount of ammonia required by such a scrubber. Mr. Farber concluded that the Coal Parties had failed to provide any evidence that the capital costs of this scrubber technology would be any less than the scrubber modeled in Vectren South's 2017 IRP Update. In rebuttal testimony, Jon K. Luttrell, Senior Vice President, Utility Operations and President of Vectren Utility Holdings, Inc., also discussed the cyber security complications and risks posed by adoption of Chinese scrubber technology.

Mr. Farber also responded to OUCC witness Aguilar's criticism that Vectren South "only" evaluated wet limestone and her presentation of potential costs for other technologies. Mr. Farber testified that dry scrubbing is not an applicable technology at A.B. Brown for technical and economic reasons, and therefore it was logical for Vectren South to evaluate wet limestone technology at A.B. Brown. He also testified the cost estimates presented by Ms. Aguilar are not comparable cost estimates to replace the existing scrubbers at A.B. Brown Units 1 and 2.

Mr. Games testified on rebuttal that there simply is no time to delay a decision and await the outcome of another IRP. The Vectren South coal units must be retired or retrofitted by December 31, 2023. Given that there has been nothing to suggest more delay would change the overall economics that the F-class 2x1 CCGT is part of the lowest cost solution under every scenario, there is no reason to believe that modeling in the next IRP would change that result. Mr. Games provided an exhibit setting forth a timeline showing that a delay to allow the next IRP to proceed would leave Vectren South with essentially no baseload capacity for almost three years. During that entire period, Vectren

South customers would be completely exposed to the market for capacity and energy. Per the redirect examination of Justin M. Joiner, Director of Regulatory Policy and MISO Affairs for Vectren Utility Holdsings, Inc. ("VUHI"), this would be during the period when MISO is projecting its largest capacity shortfall for Zone 6 (Indiana). The Commission's Director's Report states "[a]n appropriate planning aspiration is to maintain flexibility while also waiting as long as reasonably possible to commit to a resource." Mr. Games testified on cross-examination that Vectren South has waited as long as reasonably possible.

B. Modeling and Results. Only two parties presented modeling evidence and results. Vectren South presented the modeling from the 2017 IRP Update and the 2016 IRP. Sunrise Coal Witness Philip Hayet presented alternative modeling whereby Vectren South's Preferred Portfolio was delayed by seven years in order to allow existing coal units to continue to operate beyond 2023. Other parties offered criticism of Vectren South's modeling but presented no alternative modeling.

i. 2016 IRP. Vectren South's case was filed in the context of a proposed new rule to govern the IRP process. While our new rule was not effective during the 2016 IRPs, all participating electric utilities complied. This new process is significantly more transparent. It includes the participation of stakeholders, the convening of public meetings, and the submission of and response to comments. Mr. Matt Rice, Director – Research and Energy Technologies, testified regarding Vectren South's IRP process and the results of that process. Mr. Rice described Vectren's approach to its 2016 IRP process and testified Vectren South engaged several industry experts, including Burns & McDonnell and Pace Global, to conduct technical modeling. Mr. Rice testified Vectren South worked with these experts and IRP stakeholders to conduct scenario analysis to evaluate 15 portfolios, each representing a different mix of supply and demand side resources to meet customer load over a 20-year time horizon. He further testified Vectren South worked with Pace Global to conduct a risk analysis and evaluate the 15 portfolios using a balanced scorecard approach. From this analysis, Vectren South identified the "preferred portfolio" which consisted of replacing all existing coal fired generation other than Culley Unit 3 as well as gas peaking units Northeast 1 and 2 and Broadway 1 by 2024 with an F-class .05 Fired CCGT. Mr. Rice testified Vectren South incorporated stakeholder input throughout the process and described the steps Vectren South took to engage stakeholders both before and during the process. This engagement included having stakeholders develop two portfolios which were then modeled and included in the risk analysis.

Mr. Matthew Lind – Associate Project Manager, Burns & McDonnell – described the modeling Burns & McDonnell conducted in the 2016 IRP on behalf of Vectren South to evaluate its resource needs over the next 20 years. He testified the results of Burns & McDonnell's modeling identified a low-cost portfolio that ceased coal operations at Vectren South's coal fired facilities (A.B. Brown Units 1 and 2, F.B. Culley Units 2 and 3, and Warrick Unit 4) and replaced this capacity and energy with the combined cycle facility proposed here along with a simple cycle facility. Mr. Gary Vicinus – Managing Director for Utilities at Pace Global – described Pace Global's role in identifying and defining the objectives, metrics and risks in order to select the preferred portfolio among the many options. He testified Pace Global used a balanced scorecard approach to apply a risk analysis to a selection of portfolios ultimately to recommend a preferred portfolio. Mr. Vicinus further testified regarding revisions Pace Global made to its risk analysis and explained that, even with these revisions, the risk analysis indicated the preferred portfolio was the best approach.

Mr. Rice described the preferred portfolio and explained why it ranked the best on the balanced scorecard. He testified it performed the best because the portfolio is diversified as it contemplates keeping FB Culley 3 (a coal unit) and existing wind contracts, building a CCGT and introducing solar and continuing to offer energy efficiency. He further testified it is among the lower cost portfolios (within 4% of the predominantly gas lowest cost portfolio) and ultimately performed best overall when viewed across multiple measures on the balanced scorecard. Because the all-gas portfolio represented the lowest cost portfolio, it is the retention of Culley Unit 3 and the accelerated addition of the 50 MW solar project that increases the costs of the Preferred Portfolio over the lowest cost all-gas portfolio. Retention of coal and the addition of solar are essential to diversity.

ii. 2017 IRP Update. Mr. Lind testified Vectren South requested Burns & McDonnell to update the 2016 IRP modeling and the re-evaluated low-cost portfolio was consistent with the low-cost portfolio identified in the 2016 IRP. He explained that several modeling inputs were updated, including the capital cost for solar resources, variable production costs and revenue requirements for existing units, an assumed operation of Warrick Unit 4 through 2023, and updated cost assumptions for capacity, energy, natural gas, coal, and energy efficiency.

OUCC witness Peter Boerger testified regarding Vectren South's 2017 IRP Update economic modeling. Mr. Boerger testified that Vectren South's 2017 IRP Update did not adequately consider viable options for serving its customers—including making use of existing resources and adequately considering the addition of a smaller CCGT unit rather than the 2x1 unit being proposed. Mr. Boerger also testified Vectren South's modeling of the proposed CCGT understated its capital cost by $200 million, an error which disadvantaged other options in Vectren South's modeling. Mr. Boerger ultimately recommended Vectren South reevaluate its future needs and model additional alternatives.

CAC witness Tyler Comings – Senior Researcher at Applied Economics Clinic – testified on behalf of the Joint Intervenors. Mr. Comings criticized Vectren South's modeling, testifying it was too convoluted to yield a sufficiently transparent or credible result. He testified Vectren South used too many models in the selection of the preferred portfolio and that the use of many models created ample opportunity for flawed and/or inconsistent input assumptions and other settings that could create bias in favor of the preferred plan. Mr. Comings ultimately recommended Vectren South's petition be denied because, in his view, Vectren South did not provide sufficient justification for its choice to build the CCGT and continue the operation of Culley 3.

Indiana Coal Council witness Emily Medine – Principal in the consulting firm of Energy Venture Analysis, Inc. – also testified regarding Vectren South's modeling. Witness Medine testified Vectren South should have fully updated its 2016 IRP analysis, including its scenario analysis, in order to confirm its preferred resource portfolio. She further testified that such an update should include a broader analysis (including sensitivity analyses) of the relevant assumptions and factors as of a time as close to Vectren South filing its Petition as possible. Ms. Medine attributed the decision to build a CCGT to financial motivations and also opined that approval of the CCGT might be a condition to closing the Vectren South merger transaction.[2] Ms. Medine recommended that Vectren South's Petition be rejected because Vectren South has failed to show that proceeding with building the CCGT at this time is prudent, less risky, and a better decision for both customers and the environment.

[2] While this case was pending, it was announced publicly that Vectren South's holding company was the subject of an acquisition at the holding company level, which was the subject of Cause No. 45109.

Mr. Lind responded to Mr. Boerger's testimony about an alleged $200 million "error." He explained that approximately $67 million of the alleged error identified by Mr. Boerger was due to Mr. Boerger's mistaken assumption about whether modeled option costs are stated in 2017 dollars or nominal dollars in the year of incurrence. The remainder is due to Mr. Boerger's efforts to compare apples and oranges. As Mr. Lind explained, the modeling was done prior to the more refined cost estimates for the CCGT that were developed for this case. Rather than based on a design level accuracy of plus/minus 50%, the CCGT design has been refined to a plus/minus 10%. All of the other portfolios were still at plus/minus 50%. As Mr. Lind explained, to compare the other less refined portfolios to the more refined CCGT would require some additional risk factor for the other portfolios. But even if one includes the updated cost estimate, Mr. Lind testified that it doesn't change that the lowest cost portfolios still include the CCGT. Mr. Lind prepared additional modeling involving coal-to-gas conversion (which we will describe later) and which did include the more refined CCGT cost estimate. While this additional modeling used the more precise CCGT cost and therefore impacted every portfolio that included the CCGT by increasing the overall net present value ("NPV") by $54 million, the portfolios that included the CCGT were still the lowest cost portfolios compared to portfolios that did not include the CCGT. Regarding the use of the models, witnesses Lind and Vicinus confirmed that the process and modeling for Vectren South's IRP and risk analysis were consistent with the resource planning approach Pace and Burns & McDonnell have used for numerous other utilities.

(iii) Size of the Proposed CCGT. Joint Intervenors' witness Tyler Comings testified regarding the size of the proposed CCGT. Witness Comings testified that Vectren South has not provided a sufficient justification to build a CCGT of the size included in its proposal. Witness Comings also criticized Vectren South's Request for Proposals ("RFP") (which we will describe in greater detail later) which sought resources between 600 and 800 MW, because he believed Vectren South could have considered combinations of small resources that added up to 600 MW. He further testified that considering smaller options would limit the market risk exposure for ratepayers, as well as permit a combination of bids to make up a least cost alternative. Mr. Comings testified that in order to reduce ratepayers' risk, Vectren South should explore cost effective alternatives that do not require intensive capitalization, but still provide benefits to ratepayers.

OUCC witness Anthony Alvarez also testified regarding the size Vectren South is proposing for the CCGT. Mr. Alvarez testified that Vectren South currently has excess supply, and there is no resource shortfall or inadequacy that supports Vectren's proposed 850 MW CCGT. He also questioned the load forecast used in the IRP and testified Vectren South has excess supply after serving its peak load and therefore has excess capacity to offer into the market and serve new customers.

Industrial Group witness Michael Gorman also testified regarding the size of Vectren South's proposed CCGT. Mr. Gorman testified Vectren South's proposal to build an 850 MW CCGT will result in excess capacity and have a compound impact on Vectren South's cost of service because the plan increases the costs of new generation resources and results in unrecovered stranded costs from the retired resources. Mr. Gorman recommended the Commission implement mitigation measures to reduce the cost burden on customers related to stranded costs and the cost of the new CCGT. He also recommended the Commission modify the off-system sales margin treatment so that 100% of future wholesale revenues be provided to customers to offset the cost of the proposed resource plan.

Vectren South witness Carl Chapman testified on rebuttal regarding Vectren South's decision to construct an 850 MW CCGT. Mr. Chapman explained the CCGT is essentially two units -- a 700 MW baseload unit to replace 730 MWs of retiring coal unit capacity and 150 MWs of duct fired peaking capacity to replace older peaking units and provide available low cost capacity for growth and wholesale sales opportunity. The additional peaking capacity is provided by the decision to duct-fire the CCGT. The incremental cost of duct-firing the CCGT is $15 million, and that decision must be made at the time the CCGT is constructed (i.e., it cannot be added at a later time.) Mr. Chapman testified that if only the unfired 700 MW baseload CCGT is built, then by 2025, Vectren South has a projected surplus above MISO's Planning Reserve Margin ("PRM") (which fluctuates) of only 51 MW. He further testified that by 2030, the surplus is only 5 MWs and by 2031 Vectren South will fail to meet its PRM. He testified that by 2036, Vectren South will be short 39 MWs, and all of this assumes Vectren South will not add significant new load. Mr. Chapman testified that with its low capital cost, firing makes sense from a customer perspective. For an incremental cost of 2%, the firing provides a 21% increase in capacity. Nevertheless, if the Commission approves the baseload 700 MW CCGT without firing, Vectren South will proceed to construct the unfired CCGT to replace its baseload coal units. He stated that Vectren South would also consider investing the incremental $15 million to duct-fire the unit and be at risk to recoup its investment via retention of the wholesale revenue produced by that peaking capacity.

Mr. Chapman also testified regarding Industrial Group witness Gorman's recommendation that Vectren South pass off-system sales margins on to retail customers. Mr. Chapman testified that Vectren South has decided to commit to provide 100% of wholesale sales revenue from the CCGT (baseload and peaking) to customers. Mr. Chapman explained that once the CCGT is placed in rate base, the benefits from the wholesale revenue produced by the unit will go to reduce customer costs. Mr. Chapman testified that providing 100% of wholesale revenue to customers further improves the NPV of the CCGT, will provide a larger offset to customer costs in general, and adds even more support to the $15 million incremental investment to duct fire the unit.

C. Coal Parties' Modeling. Indiana Coal Council, Inc. witness Philip Hayet – Vice President of J. Kennedy and Associates, Inc. – testified regarding Vectren South's 2016 IRP modeling and the 2017 IRP Update. Mr. Hayet testified that Vectren South's modeling analyses were flawed due to errors, inconsistencies, and a lack of consideration of important factors. Mr. Hayet performed his own analysis and testified that using the same model with certain corrections, including a deferral of a decision to add a CCGT, produced a slightly lower cost result on a NPV basis. He predicated his modeling on the assumption that the A.B. Brown 2 scrubber will continue to operate reliably through 2030. He ultimately recommended that Vectren South defer its decision to construct the CCGT.

On rebuttal, Vectren South witness Matthew Lind testified regarding Indiana Coal Council witness Hayet's alternative modeling. Mr. Lind testified that when Mr. Hayet's modeling is corrected for obvious errors, it reaches the same preferred portfolio conclusion as Vectren South's modeling. Mr. Lind provided corrections to Mr. Hayet's modeling in the form of an updated Strategist model and spreadsheets documenting the corrections. Mr. Lind outlined each of the errors he identified in Mr. Hayet's modeling and the impact of the individual errors on his analysis. The first of several errors he identified was that Mr. Hayet failed to include cost escalation during the seven years of delay that he was urging and that correcting this error alone would change Mr. Hayet's overall conclusion that delay would be less costly. Mr. Lind also testified regarding the cumulative effect of

addressing all of the errors. As part of this analysis, Mr. Lind testified that he included the increased cost of the CCGT to reflect the more recent cost estimates based on a plus or minus 10% confidence level. He testified that when correcting Mr. Hayet's modeling for all of these errors and inconsistencies, the NPV favors Vectren South's preferred portfolio, even under Mr. Hayet's no carbon regulation scenario. Witness Hayet corrected his testimony after Mr. Lind filed his rebuttal to add the escalation during the period of delay he was urging, and this correction changed his original conclusion that delay was less expensive. Mr. Hayet did not address the other modeling issues raised by Mr. Lind.

Mr. Games' rebuttal testimony also addressed witness Hayet's assumption that the A.B. Brown 2 unit and scrubber could be operated without added cost and reliability risk through 2030. Apart from the reliability issues created by the frequent cycling of the unit, he explained the structural damage resulting from the corrosive environment created by the unique characteristics of these scrubbers, and based on his direct experience with this equipment, Mr. Games concluded that he could not agree that it would be prudent to continue to operate the A.B. Brown 2 scrubber for another 12 years beyond 2018.

D. Renewables and All-Source RFP. Joint Intervenor witness Tyler Comings criticized the costs assumed in Vectren South's modeling for most renewable energy sources. Mr. Comings testified that Vectren South's forecast of the capital costs of future wind resources is higher than he would have recommended for the type of planning analysis and its forecast of the fixed O&M costs are lower. Mr. Comings recommended the use of the National Renewable Energy Laboratory's Annual Technology Baseline ("ATB") to develop the forecasts. With respect to future solar resources, Mr. Comings testified Vectren South's forecasts are too high for both the capital and fixed O&M costs. Mr. Comings recommended the reliance on the ATB to develop wind and solar price forecasts. For utility-scale PV, he testified that the ATB midpoint projection would be appropriate. As part of his discussion of renewable costs, he noted that Northern Indiana Public Service Company ("NIPSCO") had recently conducted an RFP and obtained solar and wind bids. Mr. Comings testified that Vectren South's overestimation of renewable costs compared to the ATB data biased the modeling results against renewable resources in favor of non-renewable resources, such as natural gas.

On rebuttal, Mr. Lind responded to Mr. Comings' testimony related to the cost of renewables included in Vectren South's modeling. With respect to wind resources, Mr. Lind noted that prior to revising his testimony, Mr. Comings' originally filed testimony included an inaccurate and inappropriate comparison of assumed capital cost for wind resources between Vectren South and ATB because Mr. Comings failed to account for the declining cost curve over time utilized by Vectren South. Mr. Lind testified that when Mr. Comings updated his testimony to reflect this decline, he recognized that Vectren South's wind costs are only "slightly higher" than what Mr. Comings recommends. Mr. Lind further testified that even with this correction, Mr. Comings' comparison to the ATB figures is incorrect because the ATB figure excludes a 2.1% construction finance factor and is thus understated. Mr. Lind testified that when the 2.1% construction finance factor is included, the ATB capital cost will exceed Vectren South's modeled capital cost for wind over more than half of the planning period. Mr. Lind pointed out that Vectren South assumed a higher capacity factor than the ATB survey and also assumed lower O&M costs compared to the ATB survey, and as a result, it is likely that the wind prices recommended by Mr. Comings are actually higher than those modeled by Vectren South.

With respect to Mr. Comings' criticisms of Vectren South's solar costs, Mr. Lind testified Mr. Comings again failed to account for the declining cost curve over time in the original version of his testimony. Mr. Lind further testified that while Mr. Comings did update his comparison to reflect the decline, he did not update it to include the 2.1% construction finance factor in the ATB comparison. Moreover, Mr. Lind explained that the national survey costs relied upon by Mr. Comings were presented on a direct current (DC) basis, whereas the 2017 IRP Update stated cost in terms of alternating current (AC), thus requiring that Comings' costs be converted to AC to allow for a valid comparison to be made. When correcting for these additional errors, Mr. Lind testified the solar costs used by Mr. Comings and Vectren South are nearly consistent over the last half of the study period and fairly similar from 2024 onward, which is the point at which capacity is needed.

Mr. Lind also testified regarding the impact of network upgrades and congestion costs on a portfolio that would rely more heavily on renewables. Mr. Lind testified that a portfolio which would rely heavily on renewables to supply power to Vectren South's customers is more likely to source some or all of these resources remote to Vectren South's service territory given the acreage required for such projects, the grid issues that can be encountered, and the enhanced production that can be obtained in certain locations (e.g., northern Indiana). Mr. Lind explained that when significant amounts of power are sourced from off-system resources, congestion costs to Vectren South's customers increase substantially. Because such costs were not part of the 2017 IRP Update assumptions, Mr. Lind concluded that any small differences between the solar costs presented by Mr. Comings and those modeled by Vectren South would be more than offset by the congestion costs associated with greater reliance on such resources. Finally, Mr. Lind noted that even assuming lower renewable costs could be achieved, such resources would likely displace Culley Unit 3's 270 MWs of capacity because that could be done incrementally to reduce the effects of network upgrades and congestion, whereas the CCGT would remain the optimal low cost choice to replace the remaining 730 MWs of retiring coal capacity in 2023. Further, wind and solar are intermittent sources of power; given that Culley Unit 3 would be Vectren South's only baseload capacity under its preferred portfolio, dispatchable baseload generation from a CCGT provides greater flexibility to respond to intermittent resources.

E. Capacity Price Forecasts. Mr. Comings testified regarding Vectren South's ability to purchase future needed capacity from the MISO market. Mr. Comings testified that Vectren South overestimated future capacity prices in MISO in its modeling, and in reality, the MISO market has had an oversupply of resources and tempered demand, leading to low capacity prices. He testified Vectren South's assumption of higher capacity prices is critical, because it makes the economics of building a new resource more attractive. He concluded that Vectren South was placing risk on its customers if the price of capacity is lower. To reach his conclusion, he relied on the MISO auction clearing results for Zone 6 (Indiana) for the past five years. Indiana Coal Council witness Hayet had a similar criticism of Vectren South's modeled capacity prices. He agreed that the cost of new entry ("CONE") served as the upper end of future capacity prices but that, also based on MISO historic auction clearing prices, it was inappropriate for future assumed capacity prices to approximate CONE. Instead, witness Hayet proposed to use 75% of CONE.

On rebuttal, Vectren South witness Joiner responded to Mr. Comings' testimony related to Vectren South's alleged overestimation of MISO capacity prices. Mr. Joiner testified he disagreed with Mr. Comings' contention that Vectren South should assume it will be able to purchase capacity and energy from the MISO market at low prices based upon recent market conditions. Mr. Joiner explained that the MISO market has been volatile in recent years and is experiencing shrinking

capacity, and such factors have prompted MISO to evaluate changes to its market structure. Mr. Joiner testified that MISO's recent and pending market reform initiatives, including MISO's Resource Availability and Need ("RAN"), are aimed at increasing capacity and energy prices to incentivize new generation development and are thus leading to higher prices as capacity tightens. As such, Mr. Joiner testified that while MISO's historical capacity and energy prices are indicators of recent trends, contrary to Mr. Comings' MISO auction clearing price testimony, they are not good indicators of expected, long-term future pricing. Moreover, the reported potential for a capacity shortfall by 2024 shows the risk of increased market prices.

F. Refueling Options. OUCC witness Boerger recommended that Vectren model a smaller 440 MW CCGT option in conjunction with gas refueling of one or both A.B. Brown units in order to consider a lower capital cost alternative. This option, which replaces retired coal units with a smaller gas baseload unit, was consistent with his stated concern that implementation of large quantities of intermittent renewables could create grid difficulties and that the extension of the life of small coal units is not common in the industry.

Mr. Lind's rebuttal presented the results of additional modeling in response to the OUCC's interest in further analysis related to resource plan options including coal-to-gas conversion that would make use of the A.B. Brown unit boilers. Burns & McDonnell performed that modeling and analyzed four additional portfolios, each where the conversion of one or more units to natural gas was considered. Mr. Lind testified that this updated rebuttal modeling used the more refined cost estimates (at the plus/minus 10% confidence level) for the CCGT for comparison with the coal-to-gas conversion portfolios (which were stated at plus/minus 50% accuracy.) Mr. Lind described the results of the updated analysis and testified that when compared with the coal-to-gas conversion portfolios, the preferred portfolio still produces a lower NPV and projected customer cost. Witness Games explained that this is due in part to the high heat rates of refueled units which result in very poor dispatch rates and resulting reliance on the market for energy needs. He explained that such a portfolio would result in customers significantly depending on market purchases for energy. Witness Games testified the fuel cost per MWhr from a converted gas plant is roughly $20 more expensive than the cost from the proposed CCGT when gas price is $4.000/dkt. He showed the much higher heat rates and lower capacity factors at converted plants that were completed between 2013 through the first quarter of 2018. Mr. Games testified during the hearing that the problem of high heat rates means that the refueled units continue to cycle and ramp up and down when dispatched, leading to wear and tear and the risk of additional maintenance costs.

G. Docket Entry Question & Response. As a follow-up to the additional modeling performed by Vectren South on rebuttal of gas conversion options, we issued a Docket Entry requesting further iterations of gas conversion portfolios. These included refurbishment of Broadway Unit 2 coupled with delays of removal of Warrick Unit 4 and installation of either a simple cycle or combined cycle gas turbine. Vectren South's response included the more refined cost estimate of the CCGT at plus/minus 10%, excluded additional environmental compliance costs at Warrick Unit 4 that would allow for the delay, and were presented with and without the commitment by Vectren South on rebuttal to pass 100% of wholesale revenues to customers if the CCGT is approved. All of the additional modeling requested by our docket entry produced a higher NPV than the lowest cost refueling portfolio presented on rebuttal (to convert A.B. Brown and instill a simple cycle gas turbine). With the sharing of 100% of wholesale revenues, all of the additional modeling produced a higher NPV when compared to the preferred portfolio ranging from 3.5% to 7.0%. Given that the preferred portfolio was within 4% of the lowest cost 2016 IRP portfolio (CCGT, an additional

simple cycle turbine, and delayed renewables), that means the gas conversion portfolios ranged anywhere from 8-12% higher than the lowest cost portfolio.

H. Estimated Cost of CCGT and RFP Process.

i. Vectren South. Mr. Games testified that, consistent with the 2016 IRP results, the 2017 IRP Update, and the Pace risk analysis, Vectren South is proposing to build a CCGT with 700 MW of baseload capacity and 150 MW of peaking capacity to replace retiring coal-fired capacity. Mr. Games testified Vectren South is proposing to build a unit with an output of approximately 850 MWs in order to hold some additional capacity to meet its obligations as a public utility, as well as to serve potential new customers and foster economic development. The 850 MW replaces 865 MW of retiring capacity (730 MW of baseload and 135 MW of peaking capacity, including Broadway Unit 2 in 2025). Mr. Games further testified the estimated cost of the CCGT is $781 million (+/-10%). The estimate includes owner's costs and allowance for funds used during construction ("AFUDC"). This figure was based on cost estimates developed by witness Diane M. Fischer, Central Regional Area Director and Associate Vice President with Black & Veatch. Those estimates were derived from a request for proposals for all equipment comprising the CCGT as well as construction. Mr. Games testified Vectren South is proposing to construct the new CCGT on its existing A.B. Brown generating site which will provide a conservative cost savings of $50 million resulting from reusing the existing site, facilities and equipment. He explained the critical timing of the in-service date of the CCGT which will be operational for the 2023/2024 MISO capacity year in order to retire the Culley 2 and A.B. Brown units and thereby avoid material capital investments otherwise required to operate those units beyond 2023. Similarly, the Warrick Unit 4 joint operating agreement will terminate at the end of 2023. To continue to operate Warrick would also require further investment to comply with environmental regulations.

Mr. Luttrell testified regarding the other replacement generation options Vectren South considered. He described the solicitation of competitive bids for either purchased power or ownership of all or a portion of a new CCGT unit. Mr. Luttrell explained Vectren South engaged Burns & McDonnell to manage the entire power supply RFP process, and testified this process allowed Vectren South to compare the best competitive offers for dispatchable baseload capacity to several self-build alternatives, including a partnership alternative. Mr. Luttrell testified that based on this economic and qualitative comparison, Vectren South made the decision to pursue building the duct-fired version of the proposed CCGT at the existing A.B. Brown site.

Mr. Lind testified in greater depth regarding Burns & McDonnell's role in developing and managing the RFP process to address Vectren South's power supply needs. He testified Vectren South received 11 unique proposals from six different developers. He further testified each of the conforming proposals was ranked and the top two proposals were compared with Vectren South's self-build proposals. Mr. Lind testified that based on NPV cost and qualitative risk factors, including a congestion analysis related to an off-system generation project developed by a third party, Vectren South determined that the self-build option was the best resource for reliable, long term service.

ii. OUCC. Witness Alvarez testified that, while Vectren South conducted an RFP, Vectren South did not competitively bid the actual CCGT it seeks to build in this case. OUCC witness Aguilar testified that Vectren South has not yet identified a manufacturer, chosen an exact type of CCGT, or issued any bids for the project.

iii. Coal Parties. ICC witness Medine criticized Vectren South's RFP process for a number of reasons, including the contention that Vectren South was involved in the process and the self-build project did not submit a bid as part of the RFP process. ICC witness Hayet stated a similar concern. Ms. Medine also disagreed with the position that self-build projects represent less risk than merchant projects. Ms. Medine further testified regarding the risks associated with self-builds, including cost over-runs. She testified that most if not all new Indiana plants have experienced cost over-runs that utilities look to customers to recover, and unless Vectren South is willing to guarantee costs, this is a risk that should be considered.

iv. Joint Intervenors. Witness Comings testified Vectren South did not facilitate a competitive bidding process, which limited resources and discouraged bidders from offering purchased power agreements ("PPAs"). He further testified the RFP should not have been limited to MISO Zone 6 and should have been similar to other investor-owned utility solicitations.

v. Vectren South Rebuttal. Mr. Luttrell responded to the Intervenors' criticisms of Vectren South's RFP process. With respect to Mr. Comings' criticisms that Vectren South did not facilitate a competitive bidding process, including limiting resources and discouraging bidders from offering PPAs, Mr. Luttrell testified Vectren South is retiring over 70% of its baseload capacity and the RFP was specifically designed to fill that deficiency with reliable cost-effective supply identified by the IRP. Mr. Luttrell further testified PPAs were not discouraged and all four of the responsive bidders offered a PPA. Mr. Luttrell also responded to Ms. Medine's criticisms that Vectren South was involved in many aspects of the solicitation and that Vectren South did not submit a bid as part of the RFP Process. Mr. Luttrell testified Vectren South used two separate teams—one focused on the RFP and evaluation and one focused on developing the cost estimate for the Vectren South-build CCGT—and each of these teams were separate and walled off from the other. He testified Vectren South's involvement in the RFP process was critical to help ensure the RFP would meet the needs its modeling indicated was necessary. He further testified he did not believe the RFP process was negatively impacted as a result of the self-build alternative being developed parallel to the evaluation of the RFP bids, and Ms. Medine acknowledges "there is no evidence that there was inappropriate information transfer." Mr. Luttrell explained that ultimately, an evaluation of congestion costs associated with the off-system resource proposal was the driver of selecting the CCGT project at A.B. Brown as the best option.

Mr. Luttrell also responded to Ms. Medine's position that a PPA does not pose a greater risk than having a regulated utility own the generation facility. Mr. Luttrell testified that Vectren South believes that an on-system project at an existing utility site subject to regulatory oversight and financed by a public utility, is less risky than relying on a developer. He further testified that when 70% of baseload capacity is at stake, a utility should consider all risks to project completion and to ongoing service in the long term. Mr. Luttrell provided a real-life, recent example of the risks associated with relying on a developer to construct a project. Further, Mr. Luttrell testified that a PPA does represent greater risk compared to a self-build option because the financing, construction, operation, and future financial stability of the seller is not in control of either the regulated public utility or the Commission. Mr. Lind also explained that while the cost estimate for the CCGT is stated at plus/minus 10%, the risk is actually higher (plus/minus 50%) for all portfolios that do not include the CCGT.

I. Construction of Gas Lateral to Serve CCGT.

i. Vectren South. Mr. Perry Pergola – Director, Gas Supply – testified regarding Vectren South's decision to secure the interstate pipeline services of Texas Gas Transmission ("TGT") to provide natural gas service to the proposed CCGT. He testified Vectren South selected TGT because it was the least cost pipeline option to serve the CCGT at the A.B. Brown location. Mr. Pergola further testified Vectren South will build and operate a new gas lateral to interconnect with TGT and serve the CCGT.

Mr. Steve Hoover – Director of Engineering – testified regarding the 23 mile gas lateral Vectren South will construct to connect the CCGT with TGT. He testified Vectren South will construct the pipeline itself because, by virtue of its experience building, operating and maintaining new or existing gas facilities in the Vectren South service area, Vectren South is uniquely qualified and positioned to construct the new pipeline. Mr. Hoover further testified the estimated cost to construct the gas pipeline is approximately $87 million. This is not included in the estimated cost of the CCGT as presented by witnesses Fischer and Games, as it is expected the costs of the gas pipeline will be reflected in the delivered cost of the gas.

ii. OUCC. OUCC witness Alvarez testified regarding Vectren South's proposal to build the gas lateral to serve the CCGT. He testified Vectren South did not include the costs necessary to build the gas lateral in the $781 million CCGT cost estimate and should have.

iii. Industrial Group. Industrial Group witness Gorman also testified regarding Vectren South's proposal to construct a gas lateral to serve the proposed CCGT. Mr. Gorman testified Vectren South's proposal to self-build the gas lateral is not consistent with protecting the public interest and is anti-competitive. He testified that Vectren South should have considered a third party or TGT to develop the gas lateral. Mr. Gorman testified that to the extent TGT can construct a gas lateral at a lower cost than the Vectren South self-build option, then this option should be adopted. Mr. Gorman further testified that Vectren South's proposal to recover the pipeline costs as part of the fuel costs for the CCGT is not reasonable because the fixed cost to build the gas lateral will not vary with energy generation or volume of gas delivered to the CCGT. He testified instead it would be appropriate to allocate the gas lateral cost as part of the CCGT fixed capital cost of the facility and allocate it on a capacity basis.

iv. Coal Parties. ICC witness Medine testified regarding Vectren South's proposal to construct the gas lateral. Ms. Medine characterized Vectren South's proposal as a proposal to build the lateral using an affiliate without competitive bidding. She also criticized Vectren South's decision to self-build the gas lateral instead of soliciting bids from third parties. Ms. Medine testified that Vectren South did not solicit bids for the lateral from third parties, and, therefore, it cannot represent that it was the lowest cost option for the construction of the lateral.

v. Vectren South Rebuttal. Vectren South witness Steve Hoover responded to criticisms raised by the Intervenors related to Vectren South's proposal to construct the gas lateral. Mr. Hoover testified that Ms. Medine's characterization of the proposal as an "affiliate transaction" has no bearing on the overall substance of the proposed transaction because there are many reasons why it is advantageous for Vectren South to construct the gas lateral. He reiterated that the Vectren South engineering, land services, and construction management teams have already

successfully completed two similar projects to deliver gas to Duke Edwardsport and IPL Eagle Valley generating units. He testified it is therefore in the best interest of Vectren South's customers for it to enlist the experience and expertise of its gas utility in the pipeline construction and operations. Mr. Hoover also responded to criticisms raised by witnesses Gorman and Medine that the lateral project is anti-competitive and being conducted without competitive bidding. Mr. Hoover testified that Vectren South requested TGT to provide a cost estimate to construct the lateral early in the process, and TGT's cost estimate was 10-15% higher than Vectren South's estimate. He further testified that Vectren South will complete a competitive procurement process to select a contractor to construct the lateral. Mr. Hoover testified that during the course of bidding and the evaluation process, Vectren South will also incorporate cost protections and performance incentives to ensure both competitive and fair pricing.

Mr. Hoover also responded to Mr. Gorman's preference that the lateral be placed in Vectren South's rate base as opposed to the costs being recovered via the Fuel Adjustment Clause ("FAC"). Mr. Hoover testified that like IPL and Duke, Vectren South has chosen to have a qualified local distribution company ("LDC") own and operate its gas delivery pipeline. Therefore, the pipeline will not be an electric utility asset and the costs associated with it will be recovered through gas rates.

As to the allegation that Vectren South's owning the gas pipeline as a gas utility asset is anti-competitive, witness Pergola testified on cross-examination that nearly all of the pipeline (more than 22 of the 23 miles of length) is located in Kentucky and therefore presents no opportunity for bypass, because Vectren South does not possess the right to serve customers in Kentucky.

J. Warrick Unit 4.

i. Vectren South. Mr. Wayne Games testified regarding the uncertain future of Warrick Unit 4. Mr. Games explained that Vectren South and Alcoa co-own the unit pursuant to a Joint Operating Agreement ("JOA") whereby each has 50% ownership in the unit. Mr. Games testified that while Warrick Unit 4 will continue to operate in the near term, the long term outlook for the unit is uncertain. He testified the future of the unit is tied to the Alcoa industrial site, and at any time Alcoa could decide to close the smelter unit, which utilizes significant quantities of electricity produced by Warrick Unit 4, based on price volatility in the aluminum market. He testified that the decision to shut down the smelter unit would jeopardize the future of Warrick Unit 4 and this uncertainty makes it difficult to justify investment in the unit or to depend upon it in the long run.

Vectren South witness Carl Chapman also testified regarding the future of Warrick Unit 4. Mr. Chapman testified that Vectren South has agreed to retain its involvement in the unit through 2023 to support the re-opening of the Alcoa smelter. However, he testified beyond 2023 it does not makes sense to continue to invest in a unit that could be subject to shut down if Alcoa decides it has no continuing need for the capacity.

ii. OUCC. OUCC witness Aguilar testified regarding Warrick Unit 4. Ms. Aguilar testified she does not agree with Vectren South's assessments of the risk of continuing to operate Warrick Unit 4 under the JOA and she disagrees with Vectren South's "presentation of the agreement." She further testified that Vectren South could continue to operate Warrick Unit 4 beyond 2023 with environmental compliance updates.

iii. Vectren South Rebuttal. Mr. Games responded to OUCC witness Aguilar's contention that Vectren South could continue to operate Warrick Unit 4 beyond 2023. He testified that due to compliance requirements coming in Alcoa's next National Pollutant Discharge Elimination System ("NPDES") permit, it is anticipated that the unit will require significant capital investment to meet environmental standards in the future. He testified that these investments coupled with the uncertainty related to whether Alcoa will continue to operate Warrick Unit 4[3] under the JOA and performance issues at the unit, warn against continued reliance on Warrick Unit 4.

Mr. Chapman also testified regarding the continued operation of Warrick Unit 4. He testified that the partnership with Alcoa jointly to operate Warrick Unit 4 has become highly uncertain in terms of duration and no longer represents a viable long-term resource option. Mr. Chapman further testified that while Vectren South's IRP recommended retirement of Warrick Unit 4 well before 2023, Vectren South examined each of the coal units to determine whether such units should be retained. He testified that while Culley 3 and Warrick Unit 4 had better profiles in terms of environmental equipment as compared to Vectren South's other units, Culley 3 ultimately had a better operating history based on cost, availability and heat rate. Mr. Chapman reiterated that a strike against continued operation of Warrick Unit 4 is the uncertainty surrounding the longevity of the Alcoa partnership. He reiterated the continued operation of Warrick Unit 4 is dependent on the aluminum market, and if Alcoa's industrial operations cease at the site, the environmental requirements facing Warrick Unit 4 will become significantly more stringent. Mr. Chapman ultimately testified the bottom line is assuming Warrick Unit 4 can continue on post-2023 presents great risk.

As noted previously, in response to our Docket Entry question seeking additional modeling of a portfolio with delayed retirement of Warrick Unit 4, Vectren South indicated that an additional capital investment cost of as much as $50 million may be required to retain the unit if IDEM determines not to renew a variance in the unit's current NPDES permit that allows water discharge at a higher temperature. The new draft renewal NPDES permit allows IDEM to terminate this variance at any time, which will likely require the construction of a cooling tower. Coupled with both Alcoa's and Vectren South's ability to terminate the joint operating agreement, this even further increases the risk of reliance on Warrick Unit 4 beyond 2023.

K. Culley Unit 3. While making investments to preserve some coal-fired generation is not part of the lowest NPV under the 2016 IRP modeling, Vectren South proposes to make investments at Culley Unit 3, its most efficient plant, in order that it may continue to operate beyond 2023. This decision became part of the preferred portfolio as a result of the risk assessment in the 2016 IRP. Preserving Culley Unit 3 promotes greater diversity in fuel sources and it also lessens the impact on the local coal industry. Witness Retherford described the environmental controls that are needed as a result of CCR and ELG. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. Witness Fischer developed the cost estimates for the former two and Ms. Retherford provided the cost estimate for the latter. Recovery of the associated costs through a rate adjustment mechanism under Ind. Code ch. 8-1-8.4 was opposed by OUCC witness Aguilar and Industrial Group witness Gorman.

[3] With proper notice, Alcoa can also terminate the JOA.

4. Pending Summary Judgment Motion and Motion to Dismiss under T.R. 41(B). On July 19, 2018, the Coal Parties, Joint Intervenors, Evansville Western Railway, the OUCC, and the Industrial Group filed a Motion for Summary Judgment asking the Commission to vacate the schedule, arguing that we cannot grant Vectren South's request for authority to construct facilities until we have completed a "final" statewide analysis pursuant to Ind. Code § 8-1-8.5-3(a). Alternatively, the Movants asked us to grant them an extension of time to file their pre-filed testimony until at least 45 days after we post a "final" statewide analysis. We took the matter under advisement. At the conclusion of Vectren South's case-in-chief, Alliance Coal made an oral motion to dismiss under T.R. 41(B) on the same grounds. The T.R. 41(B) motion was joined by the OUCC and all of the other Movants except the Industrial Group and Evansville Railway.

In construing a statute, we start with its plain language and "attempt[] to give words their plain and ordinary meanings." *Indiana Wholesale Wine & Liquor Co., Inc. v. State ex rel. Indiana Alcoholic Beverage Com'n*, 695 N.E.2d 99, 103 (Ind., 1998) (citations omitted). "[I]n seeking to give effect to the legislature's intent, [the court] read[s] an act's sections as a whole and strive[s] to give effect to all of the provisions so that no part is held meaningless if it can be reconciled with the rest of the statute." *Fort Wayne Patrolmen's Benev. Ass'n, Inc. v. City of Fort Wayne*, 903 N.E.2d 493, 497 (Ind. Ct. App., 2009) (citation omitted).

The Motion is based primarily on Section 3(a) of Ind. Code § 8-1-8.5, which provides that "[t]he Commission shall develop, publicize, and keep current an analysis of the long range needs for expansion of facilities for generation of electricity," and Section 3(c), which provides that "[t]he commission shall consider the analysis in acting upon any petition by any utility for consideration." The Movants interpret these provisions to mean that we cannot consider a certificate of public convenience and necessity ("CPCN") request absent a "final" statewide analysis. We disagree.

Neither provision requires or implies there must be a "final" or conclusive statewide analysis. Nor does any other provision in Chapter 8.5. Section 3 directs us to undertake an "analysis" that is subject to ongoing review and revision. An analysis that must remain "current" cannot possibly remain static or culminate in a finished product. We find that the analysis detailed in the draft and final versions of the Statewide Analysis meets the requirements of the statute.

To the extent the Movants argue that we cannot grant Vectren South's Petition until we complete our annual report on the analysis, their Motion also fails.

Section 3(h) requires us "[e]ach year" to "submit to the governor and to the appropriate committees of the general assembly a report of its analysis regarding the future requirements of electricity for Indiana or this region." Ind. Code § 8-1-8.5-3(h). Section 5(b)(2) provides that a certificate may be granted if the Commission finds the project (A) "will be consistent with the Commission's analysis (or such part of the analysis as may then be developed, if any)"; or (B) is "consistent with a utility's specific proposal submitted under Section 3(e)(1) of this chapter and approved under subsection (d)." Ind. Code § 8-1-8.5-5(b)(2)(A) and (B).

This unambiguous language reflects the Legislature's understanding that new generation needs may arise at a time while the analysis or even the annual report is being developed or under revision. The Legislature granted the Commission authority to issue a CPCN rather than hold the request in abeyance until the annual report is issued.

It must be presumed that "'the legislature intended the language used in the statute be applied logically and not to bring about an unjust or absurd result.'" *D.B. v. Review Bd. of Indiana Dept. of Workforce Development*, 2 N.E.3d 705, 710 (Ind. Ct. App., 2013) (quoting *Penny v. Review Bd. of Ind. Dep't of Workforce Dev.*, 852 N.E.2d 954, 960 (Ind. Ct. App., 2006), trans. denied). Reviewing bodies also avoid "interpreting a statute in such a manner as to render its provisions mere surplusage." *Id.* (citing *In re Adoption of D.C.*, 887 N.E.2d 950, 959 (Ind. Ct. App., 2008). The Legislature cannot have meant for the Commission to hold off assessing petitions until its analysis becomes "final" (which will never occur), or even until its annual report is submitted. Thus, the statute is clear that in considering a CPCN request, pursuant to Section 5(b)(2) we can rely on whatever current statewide analysis exists or simply determine whether the proposal is consistent with the utility's own plan and reports.

In sum, the Commission retains authority to review a project at any time. Ind. Code § 8-1-8.5-5.5 expressly allows us to "commence a review of any certificate granted under this chapter" when, "in the opinion of the commission, changes in the estimate of the probable future growth of the use of electricity" call for such review. Further, "[i]f the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate." Id.

For all of the foregoing reasons, and each of them, the Motions for Summary Judgment and for Dismissal under T.R. 41(B) are denied.

5. Commission Discussion and Findings.

A. Vectren South's Request for a CPCN for a CCGT. Vectren South requests a CPCN for a proposed CCGT (approximately 850 MW) to be constructed at the current site of the A.B. Brown power plant in Posey County. Under Chapter 8.5, a public utility may not begin the construction, purchase or lease of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require, such construction, purchase or lease.

In considering a CPCN request, Chapter 8.5 requires the Commission to consider options other than the construction, purchase, or lease of an electric generating facility. *See* Ind. Code § 8-1-8.5-4.

Further, Ind. Code § 8-1-8.5-5 sets forth specific findings the Commission must make in order to approve and grant the requested CPCN. First, the Commission must make a finding, based on the evidence of the record, as to the best estimate of construction costs. Second, the Commission must find that either (a) construction will be consistent with the Commission's Statewide Analysis, if any, for the expansion of electric generation facilities, or (b) the proposed construction is consistent with a utility-specific proposal as to the future needs of consumers in the State of Indiana or in the petitioning public utility's service area [i.e., the utility's IRP]. Third, the Commission must find that public convenience and necessity require the facilities for which the CPCN is requested.[4]

[4] A fourth finding relating to coal-consuming facilities, pursuant to Ind. Code § 8-1-8.5-5(b)(4), does not apply to the proposed natural gas facilities.

"We have indicated in previous CPCN cases that 'least-cost planning' is an essential component of our [CPCN] law." *Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4 (IURC Dec. 29, 2002), *quoting Southern Indiana Gas & Electric Co.*, Cause No. 38738, at 5 (IURC Oct. 25, 1989). "We have defined 'least-cost planning' as a 'planning approach' which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* "However, we have emphasized that the [CPCN] statute does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its obligation to serve." *Id.* As this Commission has previously ruled: "[i]f an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of IC 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service." *PSI Energy, Inc.*, Cause No. 39175, at 14 (IURC May 13, 1992); *see also Joint Petition of PSI Energy, Inc. and CINCAP VII, LLC*, Cause No. 42145, at 4.

The pre-approval of long-lived power plant investment and the concurrent regulatory assurance of that investment's recovery is, at its base, the creation of fixed costs that customers will be required to pay several years into the future, perhaps as long as 30 years or more into the future. Accordingly, our consideration in this and other pre-approval requests, especially in periods of seemingly quickening technological change, must not ignore the risk that any such investment may become uneconomic over the long-term. We must acknowledge that the economic forces at work may come from other supply side options or even demand side opportunities. The supply side and demand side certificating statutes implicate this by recognizing that an optimal balance of energy resources should consider both aspects in meeting customer needs.[5] A complication in the optimizing effort is the often disparate time horizons of the supply and demand sides of the balance. The inability to adjust the long-lasting nature of the supply side of the equation in the event market conditions or demand side expectations change in a lesser time horizon introduces a risk that some measure of the supply side investment may become uneconomic within its lifetime.[6] Demand side efforts by customers as a result of the uncontroverted improving economics of customer-scale generation resources may further compound the challenge of the optimal balancing act. Reducing demand in the near term does not necessarily correspond with reduced assured supply side investment cost recovery.[7] Because unwinding assured cost recovery should an asset become uneconomic is not a commonly employed regulatory option, it is prudent to ensure during the pre-approval process that we understand and consider the risk that customers could sometime in the future be saddled with an uneconomic investment. Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request.

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[5] Indiana Code §§ 8-1-8.5-4 and -10(c)(3).

[6] This effect can be see through the recovery of lost revenues a statutory component of utility DSM programs, which is in part a function of investment, of fixed cost, that is not being consumed at the expected rate.

[7] This timing inconsistency can reduce the value of demand side efforts because they are not avoiding long-lived fixed costs previously approved and included in rates. The full incremental impacts of demand side actions which occur after the approval of long-lived fixed costs are only affected over longer periods of time when future resources must be acquired and the timing and type of resource might change as a result of cumulative demand side activities.

i. Ind. Code §§ 8-1-8.5-4.

(1) Ind. Code § 8-1-8.5-4(1). In evaluating a utility application for approval to construct new generation, the Legislature has directed us to take into account the utility's "current and potential arrangements with other electric utilities for (A) the interchange of power; (B) the pooling of facilities; (C) the purchase of power; and (D) joint ownership of facilities."

As a member of MISO, Vectren South interchanges power on a daily basis, and Vectren South's modeling considered and factored this arrangement into its decision to seek a CPCN. In addition, early in its resource selection process Vectren South identified a potential partner for a joint generation project. Witness Luttrell explained that this partner was interested in owning a minority share of a larger CCGT, and agreed to study locating such a unit on Vectren South's system. As studies ensued, the partnership appeared to be a viable resource option. As a result, the parties studied this joint ownership opportunity throughout 2017, but ultimately in January 2018 the potential partner provided notice that it would not proceed with such a project. Both Vectren South and the Commission have considered the interchange of power and pooling of facilities.

When assessing a CPCN petition, the Commission also considers the potential purchase of power by Vectren South. On June 20, 2017, Vectren South issued a RFP for dispatchable resources located in MISO Zone 6. Vectren South explained that its RFP specified this location requirement in order to satisfy MISO's requirement that a load serving entity have at least 67% of its resources located within its zone. The RFP sought dispatchable resources based upon the 2016 IRP analysis, which recommended that Vectren South retire nearly all of its baseload coal-fired capacity by the end of 2023. As a result, the RFP was designed to solicit baseload capacity to replace the 730 MWs provided by the retiring coal units. In response, Vectren South received nine qualified bids offering both PPAs and offers to build a CCGT and sell that unit or a partial interest in that unit to Vectren South. Using the expertise of Burns & McDonnell ("BMC"), Vectren South evaluated both quantitative and qualitative aspects of the competing bids. Based on BMC's analysis of the levelized cost of energy ("LCOE") of the bids, Vectren South selected the bid with the most favorable LCOE to compare to a self-build option. BMC's analysis was that Vectren South's self-build option had a better net present value than this best bid, and also exposed Vectren South to less risk versus long-term reliance on a merchant developer. Vectren South's rebuttal testimony noted that the merchant developer in question had in fact, even prior to its bid submission, withdrawn its project from the MISO queue without informing Vectren South.

The Commission acknowledges Vectren South's issuance of an RFP but believes the RFP was unduly restrictive given the rapid changes in technology and costs being seen in the market, especially regarding renewable energy. The narrow RFP with its focus on a large baseload dispatchable resource limited the options Vectren South evaluated to those larger than 600 MW. As a result, Vectren South foreclosed consideration of combinations of smaller resources that might have offered greater resource diversity, flexibility and cost efficiencies than reliance on the acquisition of a single large natural-gas facility. As discussed further below, expansion of the RFP to consider a broader spectrum of resource options would have also gone a long way to improve the metrics to limit risks from exposure to changes in market conditions and technologies.

Based on Vectren South's unduly restrictive RFP the Commission cannot conclude that Vectren South thoroughly evaluated the purchase of power in connection with Vectren South's request.

(2). Ind. Code § 8-1-8.5-4(2).

(a) The Refurbishment of Existing Facilities. In acting upon a petition for the construction of an electric generation facility, we must consider other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities. Ind. Code § 8-1-8.5-4(2). Ms. Aguilar summarized the following alternatives that Vectren South failed to fully analyze: (1) Retain Coal at Vectren South's existing plants and invest in refurbishments; (2) Retain the agreement with Alcoa for Warrick Unit 4; (3) Refuel the A.B. Brown unit(s) with gas; (4) A blended option, such as refueling one or more A.B. Brown units to gas and building a smaller CCGT; (5) Enter into a PPA with one of the bidders who responded to Vectren South's RFP; and (6) Retain its Broadway Avenue Unit 2. Pub. Ex 1, p. 8. Ms. Aguilar argued that Vectren South unfairly screened out these alternatives during the IRP process.

We agree with Ms. Aguilar and Dr. Boerger that Vectren South did not fully consider options to extend the life, or refurbish, existing units as required by Ind. Code § 8-1-8.5-4(1). *Id.* and Pub. Ex. 3, p. 6. This failure began during Vectren South's IRP process, when Vectren South screened out, without further study, viable refurbishment options. Pub. Ex. 1, p. 11. Vectren South's stated reason for shutting down the A.B. Brown units is premised on the need to replace the flue-gas desulfurization ("FGD") units at a cost of approximately $350 million. Pub. Ex. 3, p. 7. Dr. Boerger stated that with the exception of the current FGDs, the units operate quite well and are sized appropriately for a small utility like Vectren South. But as noted by Ms. Aguilar and Dr. Boerger, Vectren South's chosen FGD replacement technology was the most expensive and only technology reviewed. *Id.,* Pub. Ex. 3. Dr. Boerger pointed out that Vectren South did not consider lower-cost FGD replacement options, even though such options were available. He said that this decision made the continued use of the A.B. Brown units look less attractive in modeling than if those options had been included. A reasonable alternative would have been the refurbishment of these units through refueling. Pub. Ex. 3, p. 7. Refueling is viable, proven technology that could be accomplished at a fraction of the price of the CCGT – approximately $45 million for both A.B. Brown units.

Vectren South considered a smaller 440 MW CCGT option in its last IRP, but Vectren South did not include it as part of any refueling options. Pub. Ex. 3, p. 9. Further, when Vectren South issued its RFP, it did so for 600-800 MW of dispatchable power, precluding smaller units that might have combined with refurbishment of other Vectren South units. Tr. B-25 - B-26. Vectren South did not fully model the conversion of one of the A.B. Brown units in its rebuttal testimony. Tr. E-45 – E-46.

On cross-examination, Vectren South witness Mr. Swiz estimated that the value of the stranded assets at the A.B. Brown unit alone will equal $220 million and that the system-wide total will be $270 million. While Vectren South argues that the CCGT option is the lowest cost, we find for the many reasons stated throughout this Order, including Vectren South's failure to sufficiently consider the refurbishment and continued operation of its existing facilities, we are not able to verify this claim. Through the lens of minimizing risk and providing future flexibility the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated. This conservative solution and risk avoidance strategy stands in stark contrast to proposed CCGT. Vectren South plans to submit a new IRP in 2019. We instruct Vectren South to closely consider our analysis in this Order and the Director's Report on the 2016 IRP of the flaws in their modeling for the 2016 IRP and the 2017 IRP Update and to present a more thorough

analysis that fully evaluates all possible options for continuing to provide reliable, efficient, and economical electric service.

(b) Conservation and Load Management. The evidence demonstrates that Vectren South has evaluated the CCGT against other reasonable generation alternatives, and included demand side management and energy efficiency ("DSM/EE") levels consistent with the targets approved in Cause No. 44927. Vectren South's modeling concludes that, even when the cost of energy efficiency has been significantly lowered, the CCGT is still the least cost reliable resource alternative to meet Vectren South's customers' future energy resource needs.

The Joint Intervenors criticize the assumptions used by Vectren South to model the cost of DSM/EE, arguing that the assumptions used by Vectren South were too high resulting in a higher cost of DSM/EE. Ms. Harris stated in her rebuttal that for purposes of this proceeding, Vectren South opted only to update its growth factors in its revised cost analysis in order to show the impact lower DSM/EE costs would have on the energy resources selected in its IRP. Ms. Harris explained that limiting the updates to the growth factors preserved the integrity of Vectren South's 2016 IRP. Petitioner's Exhibit No. 8-R, p. 3. We find that while some of the cost assumptions used by Vectren South could have been updated, on the whole it does not render Vectren South's analysis of DSM/EE unreasonable.

(c) Cogeneration and Renewable Energy Sources. Vectren South's IRP modeling process considered the potential for cogeneration facilities to serve its customers and adjusted its load forecast to reflect the potential for cogeneration facilities. Petitioner's Exhibit No. 5, Attachment MAR-1, pp. 99-103. Consequently, the potential for customer-owned generation resources, including renewable generation, to reduce Vectren South's load was evaluated as part of the IRP process that concluded the CCGT was necessary as part of least-cost planning. Nonetheless, while Vectren South may have considered renewable energy in the IRP, there is a lack of evidence that Vectren South made a serious effort to determine the price and availability of renewables. In addition, the economics of customer-scale renewable and cogeneration facilities appears likely to continue to improve and we anticipate that additional well-developed efforts to understand their customers' interest would serve to provide clarity to the lens of risk avoidance by minimizing the potential for unexpected demand side efforts. Therefore, we would expect Vectren South to ensure an enhanced consideration of renewable energy and customer-generator opportunities in future IRPs.

(3) Ind. Code § 8-1-8.5-5. A certificate may be granted only if the Commission makes the followings findings:

(a) Best estimate of construction, purchase, or lease costs based on the evidence of record. The cost estimates for Vectren South's proposed CCGT were developed and presented by witness Diane Fischer. Black & Veatch developed a design basis and conceptual design and thereafter developed a cost estimate. Several conceptual designs were first developed. From that, ten plant alternatives for purposes of estimating costs were identified. This was later narrowed to seven alternatives for which detailed costs were developed. Competitive bids were obtained for the equipment and materials. Based upon Black & Veatch's experience as an engineering, procurement and construction ("EPC") contractor, Black & Veatch was able to estimate indirect costs, contingency, overhead, and profit for the EPC contractor. Bids were also received for construction. Ultimately, Ms. Fischer testified that the cost estimate for the proposed CCGT had been refined to +/- 10%. The total estimated project cost (excluding owner's costs) was $582,000,000. The owner's

costs were then provided by witness Games, including insurance, contingency, study, and AFUDC. The total cost estimate was $781,000,000.

(b) Consistency of the CCGT with Vectren South's Utility-Specific IRP and the Statewide Analysis. Ind. Code § 8-1-8.5-5(b)(2)(A) directs the Commission to determine whether Vectren South's proposed construction of a new CCGT will be consistent with the Commission's 2018 Statewide Analysis. The final version of that report was issued after the parties' pre-filing deadline, but before the evidentiary hearing and was admitted into evidence as Pet. Admin. Not. Ex. 2. Included in that report is a synopsis of information taken from the most recent IRP projects of Indiana utilities, including Vectren South.

In Appendix 12 of the Statewide Analysis, the concept of Resource Diversity is explained:

> In an electric system, resource diversity may be characterized as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide tool to ensure a stable and reliable supply of electricity. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or resilience issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes.

Vectren South's proposal to concentrate its base load capacity from five different generating units located at three different sites down to just three generating units (one of them constituting 70% of Vectren South's baseload capacity) located at two sites appears to be contrary to the concept of resource diversity.

On page 5 of the 2018 Statewide Analysis it says:

> A key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. An IRP developed by a utility should be regarded as illustrative and not a commitment for the utility to undertake.

In explaining the importance of sound long-range planning on page 56 of the 2018 Statewide Analysis, it says, "[t]he credibility of the analysis is critical to the efforts of Indiana utilities to maintain as many options as possible, which includes off ramps, to react quickly to changing circumstances and make appropriate changes in the resources." However, we find nothing in Vectren South's evidence convinces us that its proposal provides any off ramps that would allow Vectren South to react to changing circumstances and make appropriate changes in resources. To the contrary, Vectren South's proposal seems to close most off ramps for the foreseeable future.

The parties offered diametrically opposed views on the modeling offered to support the CPCN, with Vectren South pointing to its CCGT conclusion as consistent with its IRP. But that conclusion is but one part of the analysis. We have criticized utilities in the past for modeling infirmities and even penalized a utility for analysis we found lacking. In IPL's MATS case, we ordered a $10 million credit to customers to "send[] an appropriate message" to the utility. *Indianapolis Pwr. & Light Co.*, Cause No. 44242, 2013 WL 4479081 *38, 307 P.U.R.4th 311, Order p. 36 (IURC Aug. 14, 2013). We found IPL's cost/benefit study "disappointing" and noted our own "responsibility to insure that the regulatory process involves the presentation of the best evidence possible, given the facts and circumstances of a particular case." *Id.* at 35.

At the outset, Mr. Games testified that Vectren South sent a request for information ("RFI") to original equipment manufacturers ("OEM") for CCGT pricing information before Vectren South's 2016 IRP. Tr. E-89 – E-91. Mr. Chapman stated that under any of the IRP models, the CCGT is the least expensive. Tr. A-27 - A-28.

Dr. Boerger testified that Vectren South did not consider other viable options such as refueling and smaller combinations of generation assets to meet its needs, Pub. Ex. 3, p. 1 – p. 2, which would be more prudent for a small utility like Vectren South. Pub. Ex. 3, p. 5. Vectren South excluded possible options such as maintaining Culley 2, Pub. Ex. 3, pp. 11-12, and did not allow the refueling of the A.B. Brown units to be included in any of its model runs. *Id.* Vectren South kept a smaller, 440 MW CCGT from being combined with a refueled A.B. Brown unit. Pub. Ex. 3, p. 13. Mr. Games admitted that Vectren "never [ran] a risk analysis of portfolios including a 1 X 1 CCGT instead of a 2 X 1[.]" Tr. E-50. Vectren South also did not allow for proposals of joint projects to be built at it's A.B. Brown site, which would eliminate the potential for congestion problems Vectren South identified as a problem in its RFP responses. Vectren South's Strategist model limited the amount of capacity purchases that a given portfolio could make. Tr. D-73. This had the effect of automatically screening out PPAs that could have been combined with other resources to meet Vectren South's capacity needs. The Director's Report on Vectren South's 2016 IRP noted that Vectren South failed to model a wide range of gas prices, making the "range of fuel price projections… unduly limited[,]" Tr. D-85, and Vectren South's re-run of gas costs did not model higher prices in a wide enough range. Tr. D-86. As noted by Mr. Alvarez, Vectren South's model retired the BAGS 2 unit in 2024 without evidence of any engineering reason to do so. Pub. Ex. 2, pp. 13-14.

Dr. Boerger also found that Vectren South modeled the cost of its proposed CCGT to be $200 million less than the cost of the project presented in the testimony of Vectren South witness Games. Pub. Ex. 3, p. 2. The consequence of excluding $200 million in Vectren South's NPV calculation had the effect of making the CCGT option look more favorable. Pub. Ex. 3, p. 14. Without adding the $200 million back into the model runs, Vectren South's analysis is skewed. Pub. Ex. 3, p. 18 – p. 19. Mr. Games admitted that his testimony about the estimates was confusing, stating "[w]e started off with 2017 dollars, and those were -- then overheads were added, anticipated profit with the EPC, contingency for EPC, and escalation was added to get to the 582 million." Tr. E-15 – E-16. Mr. Lind took issue with Dr. Boerger's analysis, but admitted that Vectren South did not include $130 million in owner's costs when it compared its self-built CCGT to other options offered in the RFP and otherwise. Tr. A-36 – A-38; Tr. D-7 – D-8. When questioned why BMC did not use the $781 million figure, Mr. Lind stated that the $630 million estimate used for modeling was a +/- 50% estimate; the $781 million had a more certain +/- 10% range of accuracy. Tr. A-35; Tr. C-61 - C-62, C-74. BMC's projected cost of $580 - $650 million was used to weigh the economics of potential projects. Tr. A-

36 – A-38. And Vectren South witness Mr. Vicinus ran his "low regulatory" model using the $630 million estimate. Tr. D-98.

In response to the OUCC's criticism of its modeling, Vectren South's rebuttal included a new model run that refueled one of the A.B. Brown units, and added 200 MW of solar. Tr. D-12 – D-13. Vectren South used this rebuttal modeling to try to reinforce its original request for a 850 MW CCGT. Both Mr. Lind and Mr. Games acknowledged, however, that the addition of 200 MW of solar was not the best choice to meet MISO's PRM, because MISO would only give Vectren 100 MW of credit for the 200 MW of solar. Tr. E-15. The revised model also did not take into account the fact that solar costs between $1,200 - $1,800 per MW, Tr. D-16 – D-17, and Vectren South did not model any storage to counter the inherent intermittency of solar resources. Tr. D-14.

While we find Vectren South's request is "consistent" with its 2016 IRP, the subsequent modeling for this case effectively screened out multiple less-expensive alternatives. Vectren South did not allow its models to choose refueling or smaller units in combination. While Vectren South's rebuttal modeling runs included refueling of the A.B. Brown units in various configurations, the rebuttal modeling was not used to make Vectren South's decision of what generation form to choose. Tr. D-14. We view the rebuttal modeling as an after-thought used to buttress Vectren South's initial request.

Vectren South had sufficient time to conduct its analysis in a way more open to smaller-scale options that would correct the modeling deficiencies that have been identified. It seems straight-forward to suggest that smaller-scale options, especially for a relatively small electric utility, serve to minimize the risk should a challenge arise at any one option. As noted above, minimizing supply side long-term investment risk in an environment of rapid technological innovation is an attractive characteristic in a utility resource proposal. Vectren South should use its scheduled 2019 IRP process to address problems in its modeling, incorporate more options for partnering with other entities and competitive inquiries into smaller-scale options that can be acted upon swiftly to meet the end-of-2023 date upon which additional capacity may be needed.

(c) Public Convenience and Necessity. Ind. Code § 8-1-8.5-5(b)(2) requires that we find that public convenience and necessity requires or will require the proposed CCGT. Such consideration of the public interest is not only a statutory requirement at the outset but would become a continuing obligation should the Commission grant a CPCN. Ind. Code § 8-1-8.5-5.5 provides that if, after granting a CPCN for construction of a new generator, "the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate."

"[P]ublic interest may be taken to encompass a wide range of considerations, from environmental, health, and safety concerns, to the financial concerns of employers, employees, and ratepayers." *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 762 (Ind. Ct. App., 1995). In *General Motors*, the court approved the Commission's consideration of the impact on employment in the coal industry in its public interest determination. *Id.*

The parties dispute whether Vectren South accurately and adequately evaluated risk in its analysis of alternative portfolios and selection of the proposed CCGT. As noted earlier, under Ind. Code § 8-1-8.5-4, we are required to take into account other methods for providing reliable, efficient,

and economical service, and we find utility risk analyses play an important role in comparing alternative portfolios.

Joint Intervenors argued that Vectren South's risk analysis is inadequate for multiple reasons. Joint Intervenors note that the risk analysis has not been updated since the 2016 IRP, despite Vectren South having updated inputs available for several inputs, including the estimated cost of its preferred build, and adequate time to re-run the model. Joint Intervenors complain that Vectren South ignored known material risks in a manner that biased results in favor of its preferred portfolio, including taking a one-sided view of capacity purchase and market purchase risks and failing to consider the potential for future methane regulations. Joint Intervenors further argue that Vectren South arbitrarily scored several metrics and designed others to conceal rather than measure obvious risks of the preferred portfolio.

We find merit in several of Joint Intervenor's critiques and are further concerned that Vectren South has not fully responded to critiques in the Final Director's Report on the 2016 IRPs. We agree that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing, and that it has sufficient time to do so now before moving forward. Vectren South updated inputs in its possession for multiple factors, including: solar capital costs; variable production costs and revenue requirement assumptions for existing units; forecasted cost for wholesale market capacity and energy; delivered fuel prices for gas and coal; and costs associated with new energy efficiency programs. Pet. Ex. 6 at 9-10. Vectren South also had a higher capital cost estimate for its preferred build. We know Vectren South had time to use these inputs to re-run the model because (a) it did just that with some of its Strategist modeling and (b) Mr. Vicinus testified that it would have taken just three months to re-run the risk analysis modeling. Tr. p. D-66. Mr. Vicinus opined that updated risk modeling would not change the result, but we are skeptical given the number and import of the updated inputs and the significance of the proposed portfolio changes. *See Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 27 (IURC May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Before proposing a portfolio change of this magnitude, Vectren South should have taken the three months necessary to update its risk analysis modeling. Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT.

We are further concerned that Vectren South appears not to have accounted for material risks associated with its preferred portfolio. As we have previously stated, "it is appropriate that modeling take into consideration reasonable risks and unknowns." *Indianapolis Pwr. & Light Co.*, Cause No. 44794, 2017 WL 1632316, Order p. 28 (IURC Apr. 26, 2017). Joint Intervenors point out that Vectren South's risk analysis took a one-sided view of capacity purchase and market purchase risks. *See* JI Ex. 2 at 43; Vicinus Rebuttal. Vectren South offered no rebuttal explaining its one-sided view of market risk, which assumed surplus capacity and generation offers only benefits to ratepayers. JI Ex. 2 at 20-21. That view of market purchases is only true when market prices and/or load are high. JI Ex. 2 at 21. Further, Vectren South's Docket Entry response of October 5, 2018, presents portfolio results that suggest the material weight at which opportunity sales influences the analysis.[8] Heavy dependence on market revenues to support a regulated investment choice is a speculative influence that we find must be materially discounted to limit the risk of customers being saddled with

[8] The submitted table indicates that the advantage of the Preferred Portfolio in comparison to (1) BAU to Gas Conversion escalates from 1.3% to 3.5% when the opportunity sales sharing moves from 50% to 100%.

uneconomic options should such speculation unfold differently than forecasted. A metric biased in favor of portfolios with surplus generation is speculation we decline to embrace.

Vectren South's own witnesses and others acknowledged risks related to relying on gas generation, but Vectren South only considered carbon dioxide emission reductions when it evaluated environmental risk. We agree that was too narrow an approach to environmental risk and one that biased the analysis in favor of gas-fired generation.

The Commission appreciates the metrics developed and used by Vectren South in the 2016 IRP, but we agree with the Joint Intervenors that the use of these particular metrics also obscured critical characteristics of the preferred portfolio. One of Vectren South's IRP objectives was to develop a plan with flexibility to adapt to market conditions and technological change to minimize risks to shareholders and customers. Specific metrics to measure resource portfolio balance and flexibility included concentration on one technology, the number of technologies and having resources remote from Vectren South's load. A critical piece of information these metrics overlook is that the acquisition of an 850 MW resource must be evaluated relative to the load to be served. Vectren South's 2016 IRP Base peak load forecast is for the summer peak to increase from 1,109 MW in 2019 to 1,198 MW in 2036. The acquisition of an 850 MW generation facility represents approximately 77 percent of the 2019 peak load and just under 71 percent of the summer peak load for 2036. We are hard pressed to see how reliance on one facility for so much of the Vectren South system requirements is consistent with maintaining flexibility to respond to changing market conditions and technological change.

Therefore, we conclude that Vectren South's risk analysis does not adequately consider the relative risk of other methods for providing reliable, efficient, and economical electric service. The proposed large scale single resource investment for a utility of Vectren South's size does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation. As a result, we find that Vectren South has not demonstrated through the evidence of record that the public convenience and necessity require the building of an 850 MW CCGT. Therefore, Vectren South's request for a CPCN to construct a 850 MW CCGT is denied.

B. Vectren South's Request for a CPCN for Culley compliance projects and related relief. Vectren South's preferred portfolio also includes the construction of various environmental projects that Vectren South contends are needed so that Culley Unit 3 can continue to operate beyond 2023. Vectren South's petition seeks relief for these projects under Ind. Code ch. 8-1-8.4 as "federally mandated" projects.

i. Ind. Code ch. § 8-1-8.4 ("Chapter 8.4").

(1) Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-5 defines a federally mandated requirement to include "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: (2) The federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*)" and also includes "(7) Any other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States

Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy."

The description of the Culley 3 Compliance Projects was set forth in the direct testimonies of Ms. Fischer and Ms. Retherford. The Culley 3 Compliance Projects consist of (1) conversion of the current wet bottom ash collection system to a dry handling bottom ash system; (2) installation of a spray dryer evaporator system; and (3) the closure of the Culley West ash pond and construction of a new lined process water and storm water retention pond in its place. This new retention pond will be constructed on the location of the existing ash pond due to space limitations. No party disputed that the dry handling bottom ash conversion or spray dryer evaporator system qualify as compliance projects to meet federally mandated requirements. The OUCC challenged whether the closure of the existing pond qualified for relief but did not contend that it was not federally mandated. For the reasons described below, we find that these projects all constitute compliance projects to meet federally mandated requirements as those terms are defined in Ind. Code §§ 8-1-8.4-2 and -5.

Vectren South witness Retherford testified that the dry handling bottom ash system is required to comply with the ELG Rule, which was promulgated under the federal Water Pollution Control Act. Petitioner's Exhibit No. 9, p. 11. The ELG rule prohibits further wet handling of fly and bottom ash. This system will enable ash from Culley Unit 3 to be disposed of in a landfill, hauled back to a surface mine in accordance with applicable surface mining regulation or recycled rather than being washed into the ash pond as part of a water discharge.

Ms. Retherford further explained that the spray dryer evaporator system was necessary to ensure compliance with ELG-imposed limits on FGD wastewater discharge. She noted that this system functions effectively as a ZLD system and enables Vectren South to utilize the alternative ELG-imposed compliance date of December 31, 2023, and to meet future more stringent ELG wastewater discharge limits.

Ms. Retherford testified that construction of a new, lined process and storm water retention pond is required to comply with the ELG Rule. As we have already noted, projects necessary to comply with the ELG Rule, promulgated pursuant to the federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*), constitute a federally mandated requirement. The only dispute, raised by OUCC witness Aguilar, pertains to Vectren South's plans to close the existing Culley West pond so that the new lined pond can be built at the site. Witness Retherford testified that there are two reasons the Culley West pond is closing: (1) the pond was taken out of service prior to the 2015 deadline and the CCR rule requires that it be closed by 2020; and (2) the current space limitations require that the new stormwater retention and process water pond be constructed on the current location. Thus, there is no dispute that costs associated with the construction of the new lined pond are incurred pursuant to a federally mandated requirement. The dispute is whether the costs to close the Culley West pond so that the new pond can be built on top of that location, also qualify as federally mandated costs.

The OUCC identifies three reasons closure costs for the Culley West pond should not be considered federally mandated costs. First, OUCC witness Aguilar contends that Vectren South has been collecting depreciation and asset retirement costs in base rates, which include the closure of ash ponds. Public's Exhibit No. 1, p. 28. However, Vectren South witness Retherford responded that finalization of the CCR rule on April 17, 2015 imposed more stringent requirements to close the ash pond. The CCR rule imposed an obligation to dewater, cap and/or remove ponded ash. Petitioner's Exhibit No. 9-R, pp. 24-25.

On rebuttal, Mr. Swiz stated Vectren South's existing depreciation rates include an estimated level of cost of removal that was designed well before the implementation of requirements to close the ponds in accordance with the environmental regulations described by Ms. Retherford. The assumed removal costs in the demolition study provided in Cause No. 43839 (Vectren South's most recent general rate case), estimated $1.1 million to close both of the Culley Ash Ponds based on cost of backfill, grading and seeding. By comparison, the estimate for closure of one ash pond in this proceeding is $19.969 million. Petitioner's Exhibit No. 13-R, pp. 6-7; Petitioner's Administrative Notice 1.

Consequently, we find that costs associated with CCR closure have not been included in Vectren South's depreciation rates, which were last updated prior to finalization of the CCR Rule.

Second, the OUCC contends that other utilities are not tracking pond closure costs as Federally-Mandated CCR Projects. Public's Exhibit No. 1, p. 28. Vectren South witness Swiz noted that no utility had proposed such recovery yet but that one utility specifically indicated that it would present closure related activities as recoverable under the Federal Mandate Statute. Petitioner's Exhibit No. 13-R, pp. 6-7. Mr. Swiz explained that Duke, IPL and NIPSCO did not ask for recovery of their pond closure costs in the proceedings Ms. Aguilar cited, and in fact the order in Cause No. 44765 specifically notes that Duke anticipates presenting closure related activities of existing surface impoundments and their associated costs in a future proceeding. Petitioner's Exhibit No. 13-R, p. 6, citing *Duke Energy Indiana*, Cause No. 44765, at *7 (IURC May 24, 2017). Each of the cases Ms. Aguilar cited were settled cases containing non-precedential language. Nevertheless, Mr. Swiz pointed out that the NIPSCO Order in Cause No. 44872, suggests that the OUCC agreed that closure costs can be recovered as federally mandated costs. Petitioner's Exhibit No. 13-R, p. 7.

Third, the OUCC contends that Vectren South should have presented alternative suitable locations to the West Pond for consideration. However, Ms. Retherford testified that the location was chosen because there was limited space at the Culley generating station. In other words, there was not an alternate location to explore. The statutory requirement to consider options does not require a utility to present alternatives that are not practical or feasible. Accordingly, we find the Culley 3 Compliance Projects are all federally mandated requirements and that Vectren South described them in its application.

(2) Energy utilities seeking recovery of Federally Mandated Costs must establish that the costs are incurred in connection with a compliance project, including capital, operating, maintenance, depreciation, tax or financing costs and describe the costs to be recovered. Ind. Code §§ 8-1-8.4-4 and -6(b)(1)(B). We have already found that the Culley 3 Compliance Projects constitute projects required by federally mandated requirements. Consequently, the costs associated with these projects constitute Federally Mandated Costs. These costs will consist of capital, operating, maintenance, depreciation, tax and financing costs. Vectren South identified the estimated costs to be recovered as Federally Mandated Costs. Costs associated with the dry handling bottom ash handling system and spray dryer evaporator system were identified by Vectren South witness Fischer. Petitioner's Exhibit No. 6, pp. 16-18, 26-28. Costs associated with the construction of a new lined process water and storm water retention pond were identified in Ms. Retherford's testimony. Petitioner's Exhibit No. 9, Attachment AMR-1. No party disputed the cost estimates for the Culley 3 Compliance Projects. Based on the evidence presented, we find that Vectren South has identified

federally mandated costs and reasonably described those costs. Those total costs are $95 million, and they are hereby approved. Petitioner's Exhibit No. 4, p. 26.

(3) Compliance with Federally Mandated Requirements (Ind. Code §§ 8-1-8.4-6(b)(1)(C)) and 8-1-8.4-7(b)(3)). No party disputed that the Culley 3 Compliance Projects will allow Vectren South to comply with ELG and CCR or that ELG and CCR are federally mandated. We previously addressed the OUCC's objections related to appropriateness of recovery. We have already found that the ELGs and CCR Rule are federally mandated requirements within the meaning of Ind. Code §§ 8-1-8.4-5 and 8-1-8.4-6(b)(1)(A) and 8-1-8.4-7(b)(3). Based on the evidence presented, we find that Vectren South's Culley 3 Compliance Projects, will allow the utility to comply with the ELGs and the CCR Rule. Therefore, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(C).

(4) Alternative Plans for Compliance (Ind. Code §§ 8-1-8.4-6(b)(1)(D) and 8-1-8.4-7(b)(3)). Ind. Code § 8-1-8.4-6(b)(1)(D) requires the Commission to examine "[a]lternative plan that demonstrate that the proposed compliance project is reasonable and necessary." Vectren South witness Diane Fischer testified about Black & Veatch's evaluation of the ELG Compliance Program for Culley to identify potential FGD discharge water treatment alternatives and ash transport water alternatives that could be implemented to comply with the ELGs. She sponsored two written reports setting forth Black & Veatch's analyses of the alternatives. Ms. Fischer testified that each of the potential discharge treatment technology alternatives assessed by Black & Veatch were screened for design concept feasibility, capital expense and operating expense.

With respect to FGD discharge water treatment, two main treatment alternatives were considered: (1) FGD treatment and discharge; and (2) zero liquid discharge ("ZLD"). Three technology types were evaluated within these two treatment alternatives: (1) for FGD treatment and discharge, physical/chemical pretreatment with biological treatment technology, (2) for ZLD, spray dryer evaporator technology, and (3) also for ZLD, brine concentrator/crystallizer technology. Ms. Fischer testified that multiple vendors providing such technologies were evaluated. A sensitivity analysis was then performed for each technology and vendor. Ms. Fischer's Discharge Treatment Report also included a cost assessment of all alternatives considered. Petitioner's Exhibit No. 10, p. 7. Ms. Fischer testified that Black & Veatch provided Vectren South with a final overall assessment of each technology and vendor offering based on Black & Veatch's analysis and the following attributes: (1) start-up/ramp up reliability; (2) technology readiness risk; (3) adaptability to sensitivity analysis scenarios; (4) operation and control risk; (5) heat rate impact risk; (6) number of operators; (7) capital and annual O&M costs; (8) susceptibility to future environmental regulations; (9) overall financial stability and credit rating. Black & Veatch ultimately recommended that Vectren move forward to a detailed engineering phase with Stochastic Differential Equation ("SDE") type technology if the maximum FGD wastewater flow rate of between 50 and 80 gpm is achieved through future testing and operations. Ms. Fischer explained the SDE solution ranks the highest among all technologies based on the attributes discussed above and the solution is economically viable and provides a zero discharge solution if the minimum FGD wastewater flow rate of between 50 and 80 gpm is achieved. The conceptual design evaluation indicated the SDE can be feasibly located and tied into the existing equipment at Culley. In addition, Ms. Fischer stated the ZLD solution provides certainty that any future change in EPA regulations would not apply at Culley since there would be no discharge of FGD wastewater.

With respect to ash transport, Ms. Fischer described Black & Veatch's analysis to identify alternative ash transport solutions that could be implemented at Culley to comply with ELG requirements, focused specifically on identifying options for removal and dewatering of bottom ash from the Culley Unit 3 boiler with truck transport and disposal of the dry material at an off-site location. Black & Veatch evaluated two categories of technologies: (1) dry conversion of the bottom ash system and (2) closed loop wet sluicing system. For dry conversion system, Black & Veatch evaluated a submerged chain conveyor under the existing bottom ash hopper. For the closed loop wet sluicing system, Black & Veatch evaluated both a dewatering bunker and a remote submerged chain conveyor. In comparing all technologies, Black & Veatch used the following quality attributes to select the preferred treatment: technical feasibility; total installed cost, O&M cost, estimated additional manpower ("FTE"), estimated footprint, major equipment, advantage, disadvantages and reliability. Ms. Fischer's testimony discussed in detail the advantages and disadvantage of each alternative. Black & Veatch prepared cost estimates for all technologies considered for addressing ash transport water. Black & Veatch ultimately recommended the submerged chain conveyor for Culley 3 compliance with ELG requirements, due to the complexity of design and comparatively higher installed cost of the other alternatives.

The only evidence offered in opposition as being an alternative plan was the OUCC's conclusory statement about possible alternative locations for the new lined pond. As we have previously found, the chosen site was selected because there are no alternative locations.

While the Commission gives significant weight to cost-effective planning and decision making when considering alternatives, the Federal Mandate Statute does not require that a utility demonstrate that the chosen compliance plan is the least cost option. Consistent with the Commission's finding in Indianapolis Power and Light's recent proceeding, Cause No. 44794 (IURC 4/26/2017), p. 30, 2017 Ind. PUC LEXIS 114, *92, (finding "it is important that the Petersburg Station is able to continue to operate on coal and protect customers from potential price volatility in the gas markets"), a reasonable alternative can be, and often is, a solution that includes risk balancing through a diversified portfolio.

Based on the evidence presented, we find that Vectren South considered alternative plans for compliance with the ELGs and the CCR Rule. The evidence shows that the Culley 3 Compliance Projects are reasonable and necessary.

(5) Useful Life of the Facility (Ind. Code §§ 8-1-8.4-6(b)(1)(E) and 8-1-8.4-7(b)(3)). Mr. Games testified that the investments in the Culley 3 Compliance Projects will allow for the continued operation of Vectren South's most efficient coal fired unit. Ms. Retherford described the environmental regulations requiring the Culley 3 Compliance Projects in order for Culley Unit 3 to continue operating. Ms. Retherford explained how closure of the Culley West pond will extend the useful life of Culley 3, because closure of the Culley West pond is necessary to provide a suitable location to construct a new pond that can continue to take non-CCR process water discharged from Culley Unit 3 and plant stormwater (i.e. surface water) which flows into the West Pond. Without this new lined process and stormwater pond, continued operation consistent with applicable regulations would be impossible after the Culley East pond commences closure.

No party disputes that issuance of a CPCN for the Culley 3 Compliance Projects will extend the useful life of Vectren South's Culley 3 unit or that Culley 3 would be required to retire in the near future if the Culley 3 Compliance Projects are not completed.

Based on the evidence presented, we find that Vectren South has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).

(6) Conclusion. We find that the Culley 3 Compliance Projects will allow Vectren South to comply directly or indirectly with one or more federally mandated requirements and that public convenience and necessity will be served by the Culley 3 Compliance Projects.

ii. Accounting and Ratemaking Issues Associated with Culley Compliance Projects. Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3)and IC 8-1-2-42(g)(3).
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

(1) Accounting and Ratemaking Treatment for ECA. Vectren South requests authority to implement a new annual rate adjustment mechanism ("ECA") pursuant to Ind. Code § 8-1-8.4-7 for the timely and periodic recovery of 80% of the federally mandated costs. Vectren South also requests approval of proposed changes to its electric service tariff relating to the proposed ECA mechanism, including the proposed Appendix E. Ind. Code §8-1-8.4-8 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 provide that such costs include capital, AFUDC, O&M, depreciation, tax, and financing costs.

Vectren South witness Swiz described how the eligible costs associated with the Culley 3 Compliance Projects will be incorporated into the proposed ECA mechanism. He testified Vectren South will prepare in each annual filing a revenue requirement calculation accumulating all eligible costs incurred through December 31 of the previous calendar year. To provide for timely recovery, Mr. Swiz testified the proposed ECA will project an annualized level of expense related to the approved projects for the 12-month effective period. Mr. Swiz stated the annual revenue requirements

will capture eligible new capital investments (both in service and Construction Work in Progress) related to the Culley 3 Compliance Projects, multiplied by the applicable rate of return, with depreciation, O&M and property tax expenses associated with the projects, and recovery of the regulatory assets recorded through interim deferral of depreciation expense, plan development expense, and PISCC, added to the resulting total. The revenue requirement for those projects will be the basis for the recovery of 80% of the eligible revenue requirement amounts in each annual ECA filing.

Mr. Swiz also described Vectren South's proposal to defer and subsequently recover depreciation expense as well as costs associated with development of the Culley 3 Compliance Projects through the ECA. The cumulative deferred balances of the regulatory assets recorded through interim deferral of such depreciation expenses would be amortized over the remaining life of the assets (20 years) and the amortization amount would be included in the ECA revenue requirements. Mr. Swiz stated the costs of development of the projects would be included for recovery within the ECA, with the balance amortized over a period of three years.

Vectren South proposes the pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the weighted average cost of capital ("WACC"), by total new capital investment related to the approved projects. Mr. Swiz testified Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism under Cause No. 44910, which is based on a return on equity ("ROE") of 10.4% as approved in Cause Nos. 43111 and 43839, Vectren South's two most recent base rate cases. Mr. Swiz stated the equity component of the rate used in the ECA revenue requirement calculation will be grossed up for recovery of income taxes, both state and federal, at then current rates.

Mr. Swiz testified that approved recoveries within each ECA filing will be calculated by taking the billing determinants by month multiplied by the applicable rates and charges for the ECA period. Any under recoveries resulting from instances in which ECA rates and charges are not in place for a full month will be recovered as an under-recovery variance in a subsequent ECA proceeding. Vectren South proposes to allocate ECA costs pursuant to the four-coincident peak allocation percentages for Vectren South utilized in its Cause No. 43406 RCRA15 and 43405 DSMA15 rate mechanisms.

With respect to the treatment of operating income, Mr. Swiz testified Vectren South will adjust its statutory earnings test under Ind. Code § 8-1-2-42(d)(3) to include the incremental earnings from approved ECA filings.

Mr. Swiz testified Vectren South proposes to file its ECA petitions and cases in chief annually, on May 1 of each year, with new ECA rates and charges becoming effective August 1 of each year. Each filing will be based on capital investments and expenses through the twelve months ended December of the prior calendar year. Variances will be reconciled in each ECA filing and recovered over the subsequent 12 month rate effective period. Vectren South seeks approval of its proposed Sheet No. 69, Appendix E, Environmental Cost Adjustment. Additional changes to Vectren South's rate schedules in its tariff are needed to reflect that the ECA will be applied monthly.

Industrial Group witness Gorman recommended that the ELG costs associated with the Culley 3 Compliance Projects be recovered within a base rate proceeding and not through the proposed ECA. He cited Vectren South's overall rate of return and stated Vectren South's costs have declined since

the last base rate case. He also suggested that Vectren South should be permitted to recover a return on investment of no more than 9.8%.

Mr. Swiz explained on rebuttal that under the statutory test under Ind. Code § 8-1-2-42(d) and -42.3, performed in Vectren South's most recent FAC proceedings as of the time his rebuttal testimony was filed (Cause No. 38708 FAC 120), Vectren South's comprehensive earnings compared to authorized levels, including both changes in expenses and revenues, show that Vectren South is currently under-earning by approximately $6.5 million of net operating income and has been under-earning since February 2017. Mr. Swiz explained that depreciation and operating expense are driving much of these results, and Mr. Gorman does not capture those expenses in his calculation.

Eligibility for recovery through Ind. Code ch. 8-1-8.4 is not contingent on whether other costs have declined to offset the new federally mandated costs. Once we have made the required findings, 80% of the federally mandated costs "shall be recovered by the energy utility through a periodic retail rate adjustment mechanism." Ind. Code § 8-1-8.4-7(c)(1). In any event, we find that Mr. Swiz has adequately explained why Mr. Gorman's position is incorrect.

Mr. Swiz testified that pursuant to Ind. Code § 8-1-8.4-7, Vectren South seeks ratemaking treatment for 80% of the costs associated with the Culley 3 Compliance Projects through its proposed ECA mechanism. Specifically, Vectren South seeks timely recovery of all federally mandated costs associated with the Culley 3 Compliance Projects, including capital costs, AFUDC, post-in-service carrying cost charges ("PISCC"), O&M, depreciation expense, property tax expense, and other taxes, with 80% recovered through the ECA and the balance deferred for recovery in Vectren South's next rate case.

Vectren South proposes to implement construction work in progress ("CWIP") ratemaking treatment related to the recovery of financing costs incurred during construction of the Culley 3 Compliance Projects. In connection with CWIP ratemaking treatment, Vectren South will remove from the AFUDC-eligible balance the amount of investment included for recovery in the ECA, so that only the amount of the Culley 3 Compliance Projects investment not currently being recovered in the ECA would be eligible for AFUDC.

Mr. Swiz testified that Vectren South proposes to accrue post-in-service carrying charges on all eligible new capital investment from the date it is placed in service until the date it is included in rates. He explained the PISCC balances will be multiplied by the pre-tax rate of return within the ECA revenue requirement, at the WACC rate described herein. Unlike other utilities who have been granted such authority, Vectren South is not seeking to accrue and subsequently recover in the next base rate case PISCC on the 20% deferred balance discussed below.

OUCC witness Aguilar opposed Vectren South's request to recover pond closure costs for the Culley 3 Compliance Projects as part of the ECA because the OUCC's position is that Vectren South is already collecting pond closure costs within its depreciation rates. Ms. Aguilar also testified that neither Duke, IPL, nor NIPSCO are tracking pond closure costs. We have already addressed these positions and rejected them.

Based on the evidence presented, we find that the proposed ECA mechanism should allow for the timely and periodic recovery of 80% of Vectren South's approved federally mandated costs. We further find that Vectren South's request for approval to adjust its authorized net operating income to

reflect an approved earnings associated with the Culley 3 Compliance Project for purposes of Ind. Code §§ 8-1-2-42(d)(3) and 8-1-2-42(g)(3) is consistent with Ind. Code § 8-1-8.4-7(c)(1).

Vectren South is authorized to defer (until captured within the ECA mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Culley 3 Compliance Projects through the approved ECA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing, and carrying costs based on the current overall WACC and AFUDC. Vectren South is authorized to utilize CWIP ratemaking treatment for the Culley 3 Compliance Projects through the proposed ECA mechanism. Vectren South is authorized to defer post-in service costs of the Culley 3 Compliance Projects, including carrying costs based on the current overall WACC, depreciation, taxes and operating and maintenance expenses on an interim basis until such costs are recognized for ratemaking purposes through Vectren South's ECA mechanism or otherwise included for recovery in Vectren South's base rates in its next general rate case. Vectren South is authorized to defer and recover through the ECA mechanism 80% of its federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Culley 3 Compliance Projects described in Vectren South's evidence. Vectren South's proposed cost allocation factors are also approved.

(2) Accounting and Ratemaking Treatment for Deferred Costs. Indiana Code § 8-1-8.4-8 provides that 20% of the approved federally mandated costs, including depreciation, AFUDC, and PISCC, based on the overall cost of capital most recently approved by the Commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the Commission. Vectren South proposes to defer as a regulatory asset 20% of all federally mandated costs incurred in connection with these projects.

Based on the evidence presented, the Commission finds Vectren South is authorized to defer 20% of the federally mandated costs incurred in connection with the Culley 3 Compliance Projects, and Vectren South may recover the deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2).

(3) Depreciation Treatment. Vectren South proposes to utilize a depreciation rate of 5%, representing a 20-year life on these investments. Mr. Swiz testified the proposed depreciation rate for the investments aligns with the estimated remaining life of Culley Unit 3.

No party opposed Vectren South's proposed depreciation rate for the investments required for the Culley 3 Compliance Projects.

Based on the evidence presented, we find that Vectren South's proposal to depreciate the individual projects included in the Culley 3 Compliance Projects based on a 5% depreciation rate is reasonable and is approved.

C. Recovery of Prior Pollution Control Investments. Our January 28, 2015 and June 22, 2016 Orders in Cause No. 44446 (the "44446 Orders") (1) granted Vectren South a CPCN for A.B. Brown Unit 1 and 2, Culley Unit 3 and Warrick Unit 3 clean coal technology projects and (2) authorized Vectren South to recover federally mandated costs associated with federally mandated requirements at A.B. Brown Units 1 and 2 (collectively the "MATS Projects"). Rather than recovering

the costs of the MATS Projects through a tracking mechanism as authorized by Ind. Code § 8-1-8.4-7, Vectren South sought, and we granted, authority to defer these costs for recovery in a future proceeding. Vectren South now seeks to commence recovery of the MATS Projects' costs through the ECA pursuant to Ind. Code § 8-1-8.4-7.

Vectren South witness Swiz described the proposed recovery through the ECA in more detail. He indicated that Vectren South proposes recovery of the MATS Projects to begin on January 1, 2019 with the approval of ECA rates and charges recovering the specified revenue requirement. In accordance with applicable statutory requirements, Vectren South proposes to recover the 80% of eligible revenue requirements amounts for post-in-service carrying costs, incremental depreciation and property taxes and financing costs that Vectren South incurred to construct the MATS Projects and deferral of the remaining 20% of these costs for subsequent recovery in a base rate case. Vectren South will prepare an annual revenue requirement as part of the ECA to capture eligible capital investments in plant related to the MATS Projects, multiplied by the applicable rate of return, with depreciation, O&M, and property tax expenses associated with the MATS Projects added to the resulting total. To provide for timely recovery, Vectren South's proposed ECA will project an annualized level of expense related to these approved projects for the 12-month effective period.

Depreciation associated with the MATS Projects will be based on the currently approved depreciation rates applicable to the assets, as approved in Vectren South's last electric base rate case (Cause No. 43839). The pre-tax return on the new capital investment will be calculated by multiplying the pre-tax rate of return, based on the WACC, by total new capital investment related to the approved projects. Vectren South proposes to use a WACC in the ECA based upon the most recent approved WACC within Vectren South's TDSIC mechanism, Cause No. 44910. This WACC, approved by the Commission, represents an updated actual capital structure as of the cut-off date of each TDSIC filing, and includes the typical items captured in Vectren South's base rate case capital structure. This rate will be used in the ECA revenue requirement calculation, and the equity component will be grossed up for recovery of income taxes, both state and federal, at then current rates. O&M expense included for recovery in the ECA will reflect an annualized level of expense related to the MATS Projects. This O&M expense represents incremental chemical costs and other expenses associated only with the MATS Projects.

No party objected to Vectren South's proposal to commence recovery of the MATS Projects' costs, currently being deferred, through the ECA. We previously found the MATS Projects costs qualify as federally mandated costs in the 44446 Orders. While Vectren South proposed, and we approved of, deferral of these costs in lieu of the recovery through a periodic retail rate adjustment mechanism, Vectren South now seeks to recover the costs in accordance with Ind. Code § 8-1-8.4-7(c). We find that Vectren South shall be authorized to commence recovery of these MATS Projects' costs pursuant to Ind. Code § 8-1-8.4-7 through the ECA in accordance with the procedures outlined in Mr. Swiz's testimony.

6. Confidentiality. Vectren South filed motions for protection and nondisclosure of confidential and proprietary information on March 20, 2018, August 21, 2018, and September 10, 2018, respectively. In its motions, Vectren South states certain information redacted in the evidence is confidential, proprietary, competitively sensitive, and/or trade secrets. Docket entries were issued on March 29, August 27, and October 4, 2018 finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the

information for which Vectren South seeks confidential treatment is confidential trade secret information pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. Vectren South's request for a certificate of public convenience and necessity under Ind. Code ch. 8-1- 8.5 to construct an 850 MW CCGT and all associated relief requested is denied.

2. Vectren South's request for a certificate of public convenience and necessity for the Culley 3 Compliance Projects pursuant to Ind. Code ch. 8-1-8.4 and all associated relief requested is approved.

3. Vectren South's proposed recovery of federally mandated costs approved in connection with Cause No. 44446 through the ECA is approved as described in this Order.

4. Vectren South's proposed ECA, and Vectren South's proposed Sheet No. 69, Appendix E of its tariff to implement such ECA is approved.

5. The Confidential Information submitted under seal in this Cause pursuant to Vectren South's requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

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

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

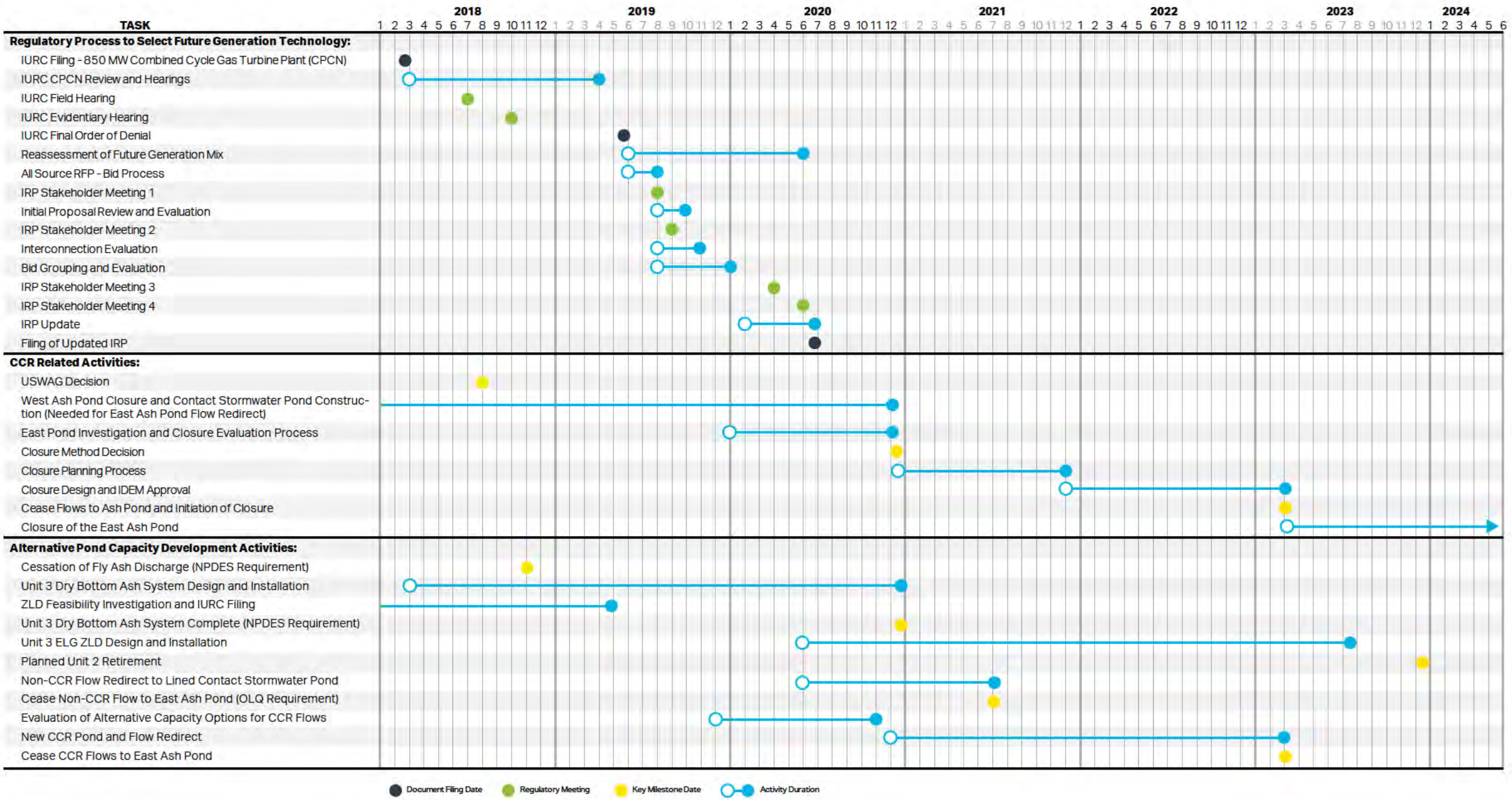
APPROVED: APR 24 2019

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

Mary M Becerra

Mary M. Becerra
Secretary of the Commission

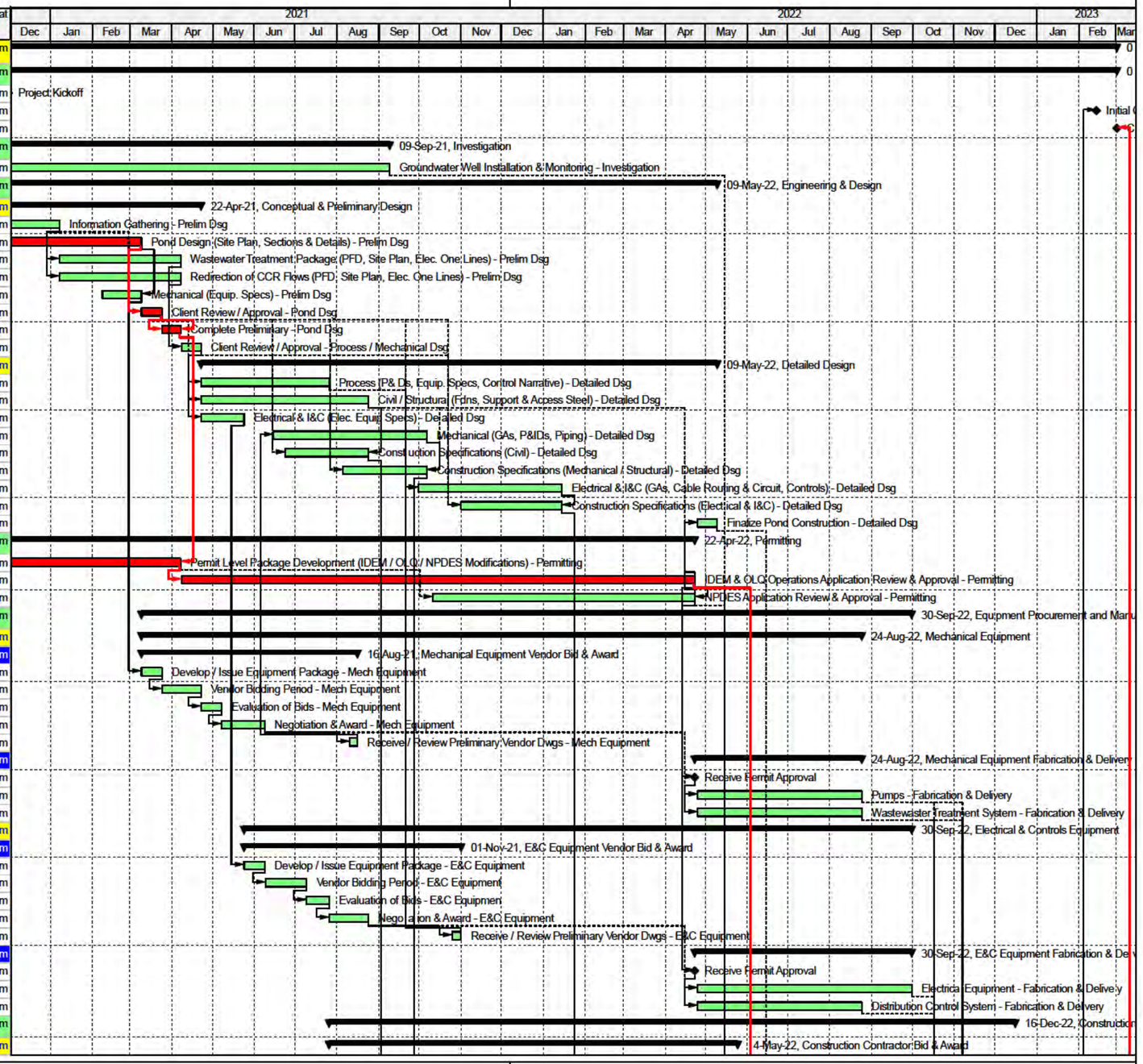
Appendix B
Schedule Activities and Milestone


TASK
2018
2019
2020
2021
2022
2023
2024
1 2 3 4 5 6 7 8 9 10 11 12
Regulatory Process to Select Future Generation Technology:
IURC Filing - 850 MW Combined Cycle Gas Turbine Plant (CPCN)
IURC CPCN Review and Hearings
IURC Field Hearing
IURC Evidentiary Hearing
IURC Final Order of Denial
Reassessment of Future Generation Mix
All Source RFP - Bid Process
IRP Stakeholder Meeting 1
Initial Proposal Review and Evaluation
IRP Stakeholder Meeting 2
Interconnection Evaluation
Bid Grouping and Evaluation
IRP Stakeholder Meeting 3
IRP Stakeholder Meeting 4
IRP Update
Filing of Updated IRP
CCR Related Activities:
USWAG Decision
West Ash Pond Closure and Contact Stormwater Pond Construction (Needed for East Ash Pond Flow Redirect)
East Pond Investigation and Closure Evaluation Process
Closure Method Decision
Closure Planning Process
Closure Design and IDEM Approval
Cease Flows to Ash Pond and Initiation of Closure
Closure of the East Ash Pond
Alternative Pond Capacity Development Activities:
Cessation of Fly Ash Discharge (NPDES Requirement)
Unit 3 Dry Bottom Ash System Design and Installation
ZLD Feasibility Investigation and IURC Filing
Unit 3 Dry Bottom Ash System Complete (NPDES Requirement)
Unit 3 ELG ZLD Design and Installation
Planned Unit 2 Retirement
Non-CCR Flow Redirect to Lined Contact Stormwater Pond
Cease Non-CCR Flow to East Ash Pond (OLQ Requirement)
Evaluation of Alternative Capacity Options for CCR Flows
New CCR Pond and Flow Redirect
Cease CCR Flows to East Ash Pond
Document Filing Date
Regulatory Meeting
Key Milestone Date
Activity Duration

Appendix C
Detailed Schedule for Development of Alternative Capacity

FBC New Lined CCR Pond_RevH | RevH | Data Date: 30-Nov-20

Activity ID	Activity Name	Duration	Start	Finish	Total Float
FBC New Lined CCR Pond_RevH		25.7m	01-Dec-20	01-Mar-23	0.0m
Milestones		25.7m	01-Dec-20	01-Mar-23	0.0m
A1350	Project Kickoff	0.0m	01-Dec-20*		0.0m
A1360	Initial Operation	0.0m	14-Feb-23		0.5m
A1750	Cease Flows to East Ash Pond	0.0m		01-Mar-23*	0.0m
Investigation		9.0m	01-Dec-20	09-Sep-21	8.8m
A1010	Groundwater Well Installation & Monitoring - Investigation	9.0m	01-Dec-20	09-Sep-21	8.8m
Engineering & Design		16.5m	01-Dec-20	09-May-22	2.3m
Conceptual & Preliminary Design		4.5m	01-Dec-20	22-Apr-21	3.3m
A1000	Information Gathering - Prelim Dsg	1.0m	01-Dec-20	07-Jan-21	2.0m
A1020	Pond Design (Site Plan, Sections & Details) - Prelim Dsg	3.0m	01-Dec-20	09-Mar-21	0.0m
A1040	Wastewater Treatment Package (PFD, Site Plan, Elec. One Lines) - Prelim	3.0m	07-Jan-21	07-Apr-21	3.3m
A1430	Redirection of CCR Flows (PFD, Site Plan, Elec. One Lines) - Prelim Dsg	3.0m	07-Jan-21	07-Apr-21	3.3m
A1540	Mechanical (Equip. Specs) - Prelim Dsg	1.0m	08-Feb-21	09-Mar-21	3.1m
A1450	Client Review / Approval - Pond Dsg	0.5m	09-Mar-21	24-Mar-21	0.0m
A1640	Complete Preliminary - Pond Dsg	0.5m	24-Mar-21	07-Apr-21	0.0m
A1740	Client Review / Approval - Process / Mechanical Dsg	0.5m	08-Apr-21	22-Apr-21	3.3m
Detailed Design		12.0m	22-Apr-21	09-May-22	2.3m
A1050	Process (P&IDs, Equip. Specs, Control Narrative) - Detailed Dsg	3.0m	22-Apr-21	26-Jul-21	6.5m
A1070	Civil / Structural (Fdns, Support & Access Steel) - Detailed Dsg	4.0m	22-Apr-21	24-Aug-21	4.5m
A1560	Electrical & I&C (Elec. Equip Specs) - Detailed Dsg	1.0m	22-Apr-21	24-May-21	3.3m
A1060	Mechanical (GAs, P& Ds, Piping) - Detailed Dsg	3.7m	15-Jun-21	06-Oct-21	3.1m
A1090	Construction Specifications (Civil) - Detailed Dsg	2.0m	23-Jun-21	24-Aug-21	6.3m
A1610	Construction Specifications (Mechanical / Structural) - Detailed Dsg	2.0m	05-Aug-21	06-Oct-21	3.1m
A1080	Electrical & I&C (GAs, Cable Routing & Circuit, Controls) - Detailed Dsg	3.0m	30-Sep-21	14-Jan-22	3.3m
A1440	Construction Specifications (Electrical & I&C) - Detailed Dsg	2.0m	01-Nov-21	14-Jan-22	3.3m
A1270	Finalize Pond Construction - Detailed Dsg	0.5m	25-Apr-22	09-May-22	2.3m
Permitting		16.0m	01-Dec-20	22-Apr-22	0.8m
A1030	Permit Level Package Development (IDEM / OLQ / NPDES Modifications)	4.0m	01-Dec-20	07-Apr-21	0.0m
A1100	IDEM & OLQ Operations Application Review & Approval - Permitting	12.0m	08-Apr-21	22-Apr-22	0.0m
A1110	NPDES Application Review & Approval - Permitting	6.0m	11-Oct-21	22-Apr-22	0.8m
Equipment Procurement and Manufacture		18.2m	09-Mar-21	30-Sep-22	1.1m
Mechanical Equipment		17.0m	09-Mar-21	24-Aug-22	2.3m
Mechanical Equipment Vendor Bid & Award		5.2m	09-Mar-21	16-Aug-21	3.1m
A1120	Develop / Issue Equipment Package - Mech Equipment	0.5m	09-Mar-21	24-Mar-21	3.1m
A1130	Vendor Bidding Period - Mech Equipment	1.0m	24-Mar-21	22-Apr-21	3.1m
A1140	Evaluation of Bids - Mech Equipment	0.5m	22-Apr-21	07-May-21	3.1m
A1150	Negotiation & Award - Mech Equipment	1.0m	07-May-21	08-Jun-21	3.1m
A1550	Receive / Review Preliminary Vendor Dwgs - Mech Equipment	0.2m	10-Aug-21	16-Aug-21	3.1m
Mechanical Equipment Fabrication & Delivery		4.0m	22-Apr-22	24-Aug-22	2.3m
A1290	Receive Permit Approval	0.0m		22-Apr-22	2.3m
A1160	Pumps - Fabrication & Delivery	4.0m	25-Apr-22	24-Aug-22	2.3m
A1170	Wastewaster Treatment System - Fabrication & Delivery	4.0m	25-Apr-22	24-Aug-22	2.3m
Electrical & Controls Equipment		15.7m	24-May-21	30-Sep-22	0.8m
E&C Equipment Vendor Bid & Award		5.2m	24-May-21	01-Nov-21	3.3m
A1490	Develop / Issue Equipment Package - E&C Equipment	0.5m	24-May-21	08-Jun-21	3.3m
A1500	Vendor Bidding Period - E&C Equipment	1.0m	09-Jun-21	09-Jul-21	3.3m
A1510	Evaluation of Bids - E&C Equipment	0.5m	09-Jul-21	26-Jul-21	3.3m
A1520	Negotiation & Award - E&C Equipment	1.0m	26-Jul-21	24-Aug-21	3.3m
A1530	Receive / Review Preliminary Vendor Dwgs - E&C Equipment	0.2m	25-Oct-21	01-Nov-21	3.3m
E&C Equipment Fabrication & Delivery		5.2m	22-Apr-22	30-Sep-22	0.8m
A1730	Receive Permit Approval	0.0m		22-Apr-22	0.8m
A1180	Electrical Equipment - Fabrication & Delivery	5.2m	25-Apr-22	30-Sep-22	0.8m
A1190	Distribution Control System - Fabrication & Delivery	4.0m	25-Apr-22	24-Aug-22	2.0m
Construction		16.0m	26-Jul-21	16-Dec-22	1.7m
Construction Contractor Bid & Award		9.5m	26-Jul-21	24-May-22	2.0m

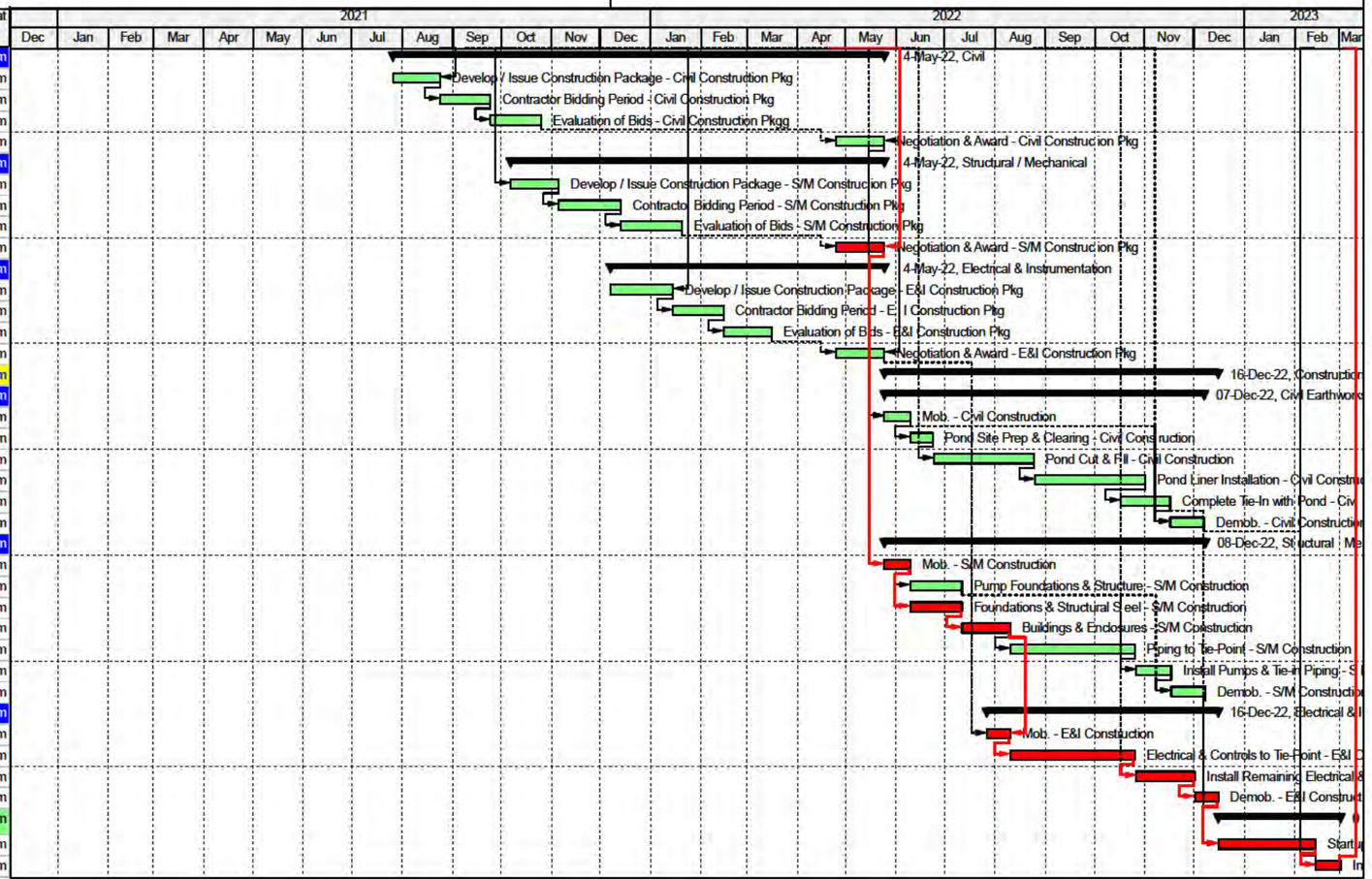


Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

AECOM

FBC New Lined CCR Pond_RevH | RevH | Data Date: 30-Nov-20

Activity ID	Activity Name	Duration	Start	Finish	Total Float
Civil		9.5m	26-Jul-21	24-May-22	0.8m
A1200	Develop / Issue Construction Package - Civil Construction Pkg	1.0m	26-Jul-21	24-Aug-21	6.3m
A1210	Contractor Bidding Period - Civil Construction Pkg	1.0m	24-Aug-21	24-Sep-21	6.3m
A1220	Evaluation of Bids - Civil Construction Pkgg	1.0m	24-Sep-21	25-Oct-21	6.3m
A1230	Negotiation & Award - Civil Construction Pkg	1.0m	25-Apr-22	24-May-22	0.8m
Structural / Mechanical		7.1m	06-Oct-21	24-May-22	0.0m
A1570	Develop / Issue Construction Package - S/M Construction Pkg	1.0m	06-Oct-21	05-Nov-21	3.1m
A1580	Contractor Bidding Period - S/M Construction Pkg	1.0m	05-Nov-21	13-Dec-21	3.1m
A1590	Evaluation of Bids - S/M Construction Pkg	1.0m	13-Dec-21	20-Jan-22	3.1m
A1600	Negotiation & Award - S/M Construction Pkg	1.0m	25-Apr-22	24-May-22	0.0m
Electrical & Instrumentation		5.3m	07-Dec-21	24-May-22	2.0m
A1390	Develop / Issue Construction Package - E&I Construction Pkg	1.0m	07-Dec-21	14-Jan-22	3.3m
A1400	Contractor Bidding Period - E&I Construction Pkg	1.0m	14-Jan-22	14-Feb-22	3.3m
A1410	Evaluation of Bids - E&I Construction Pkg	1.0m	14-Feb-22	16-Mar-22	3.3m
A1420	Negotiation & Award - E&I Construction Pkg	1.0m	25-Apr-22	24-May-22	2.0m
Construction		6.5m	24-May-22	16-Dec-22	1.7m
Civil Earthworks		6.2m	24-May-22	07-Dec-22	2.0m
A1240	Mob. - Civil Construction	0.5m	24-May-22	09-Jun-22	0.8m
A1250	Pond Site Prep & Clearing - Civil Construction	0.5m	09-Jun-22	23-Jun-22	0.8m
A1260	Pond Cut & Fill - Civil Construction	2.0m	24-Jun-22	24-Aug-22	0.8m
A1280	Pond Liner Installation - Civil Construction	2.2m	25-Aug-22	01-Nov-22	0.8m
A1630	Complete Tie-In with Pond - Civil Construction	1.0m	17-Oct-22	16-Nov-22	0.8m
A1470	Demob. - Civil Construction	0.5m	16-Nov-22	07-Dec-22	2.0m
Structural / Mechanical		6.3m	24-May-22	08-Dec-22	0.3m
A1620	Mob. - S/M Construction	0.5m	24-May-22	09-Jun-22	0.0m
A1650	Pump Foundations & Structure - S/M Construction	1.0m	09-Jun-22	11-Jul-22	3.8m
A1670	Foundations & Structural Steel - S/M Construction	1.0m	09-Jun-22	11-Jul-22	0.0m
A1680	Buildings & Enclosures - S/M Construction	1.0m	11-Jul-22	10-Aug-22	0.0m
A1690	Piping to Tie-Point - S/M Construction	2.5m	10-Aug-22	25-Oct-22	0.3m
A1700	Install Pumps & Tie-in Piping - S/M Construction	0.8m	26-Oct-22	17-Nov-22	0.3m
A1710	Demob. - S/M Construction	0.5m	17-Nov-22	08-Dec-22	0.3m
Electrical & Instrumentation		4.5m	26-Jul-22	16-Dec-22	0.0m
A1340	Mob. - E&I Construction	0.5m	26-Jul-22	10-Aug-22	0.0m
A1320	Electrical & Controls to Tie-Point - E&I Construction	2.5m	10-Aug-22	25-Oct-22	0.0m
A1480	Install Remaining Electrical & Controls - E&I Construction	1.0m	26-Oct-22	01-Dec-22	0.0m
A1460	Demob. - E&I Construction	0.5m	01-Dec-22	16-Dec-22	0.0m
Start-Up & Commissioning		2.2m	16-Dec-22	01-Mar-23	0.0m
A1370	Startup & Commissioning	1.7m	16-Dec-22	14-Feb-23	0.0m
A1380	Initial Operation	0.5m	14-Feb-23	01-Mar-23	0.0m

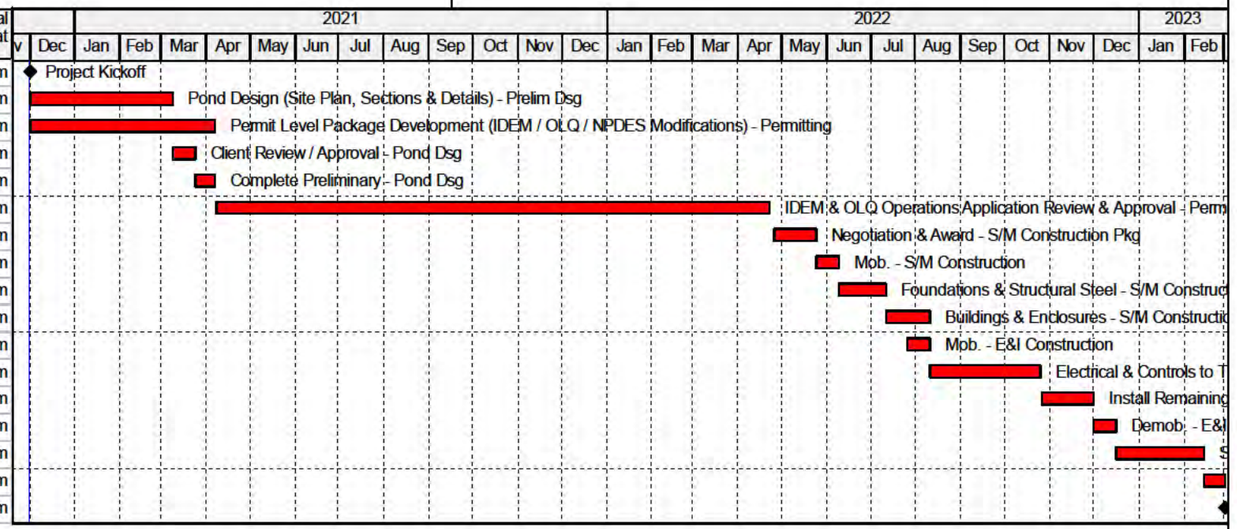


Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

AECOM

FBC New Lined CCR Pond_RevH | RevH | Data Date: 30-Nov-20

Activity ID	Activity Name	Orig. Dur.	Start	Finish	Total Float
A1350	Project Kickoff	0.0m	01-Dec-20*		0.0m
A1020	Pond Design (Site Plan, Sections & Details) - Prelim Dsg	3.0m	01-Dec-20	09-Mar-21	0.0m
A1030	Permit Level Package Development (IDEM / OLQ / NPDES Modifications) - Permitting	4.0m	01-Dec-20	07-Apr-21	0.0m
A1450	Client Review / Approval - Pond Dsg	0.5m	09-Mar-21	24-Mar-21	0.0m
A1640	Complete Preliminary - Pond Dsg	0.5m	24-Mar-21	07-Apr-21	0.0m
A1100	IDEM & OLQ Operations Application Review & Approval - Permitting	12.0m	08-Apr-21	22-Apr-22	0.0m
A1600	Negotiation & Award - S/M Construction Pkg	1.0m	25-Apr-22	24-May-22	0.0m
A1620	Mob. - S/M Construction	0.5m	24-May-22	09-Jun-22	0.0m
A1670	Foundations & Structural Steel - S/M Construction	1.0m	09-Jun-22	11-Jul-22	0.0m
A1680	Buildings & Enclosures - S/M Construction	1.0m	11-Jul-22	10-Aug-22	0.0m
A1340	Mob. - E&I Construction	0.5m	26-Jul-22	10-Aug-22	0.0m
A1320	Electrical & Controls to Tie-Point - E&I Construction	2.5m	10-Aug-22	25-Oct-22	0.0m
A1480	Install Remaining Electrical & Controls - E&I Construction	1.0m	26-Oct-22	01-Dec-22	0.0m
A1460	Demob. - E&I Construction	0.5m	01-Dec-22	16-Dec-22	0.0m
A1370	Startup & Commissioning	1.7m	16-Dec-22	14-Feb-23	0.0m
A1380	Initial Operation	0.5m	14-Feb-23	01-Mar-23	0.0m
A1750	Cease Flows to East Ash Pond	0.0m		01-Mar-23*	0.0m



Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

AECOM

Appendix D
Certification of Compliance

Certification of Compliance

In accordance with 40 CFR §257.103(f)(1)(iv)(B)(1), I, Angila Retherford, being a qualified representative of Southern Industrial Gas & Electric Company, do hereby certify, to the best of my knowledge, information, and belief, that the F.B. Culley Generating Station is in compliance with all of the requirements of 40 CFR 257 Subpart D – Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments. F.B. Culley's CCR Compliance website is up-to-date and contains all the necessary documentation and notification postings.

Angila Retherford

Signed

Angila Retherford

Printed Name

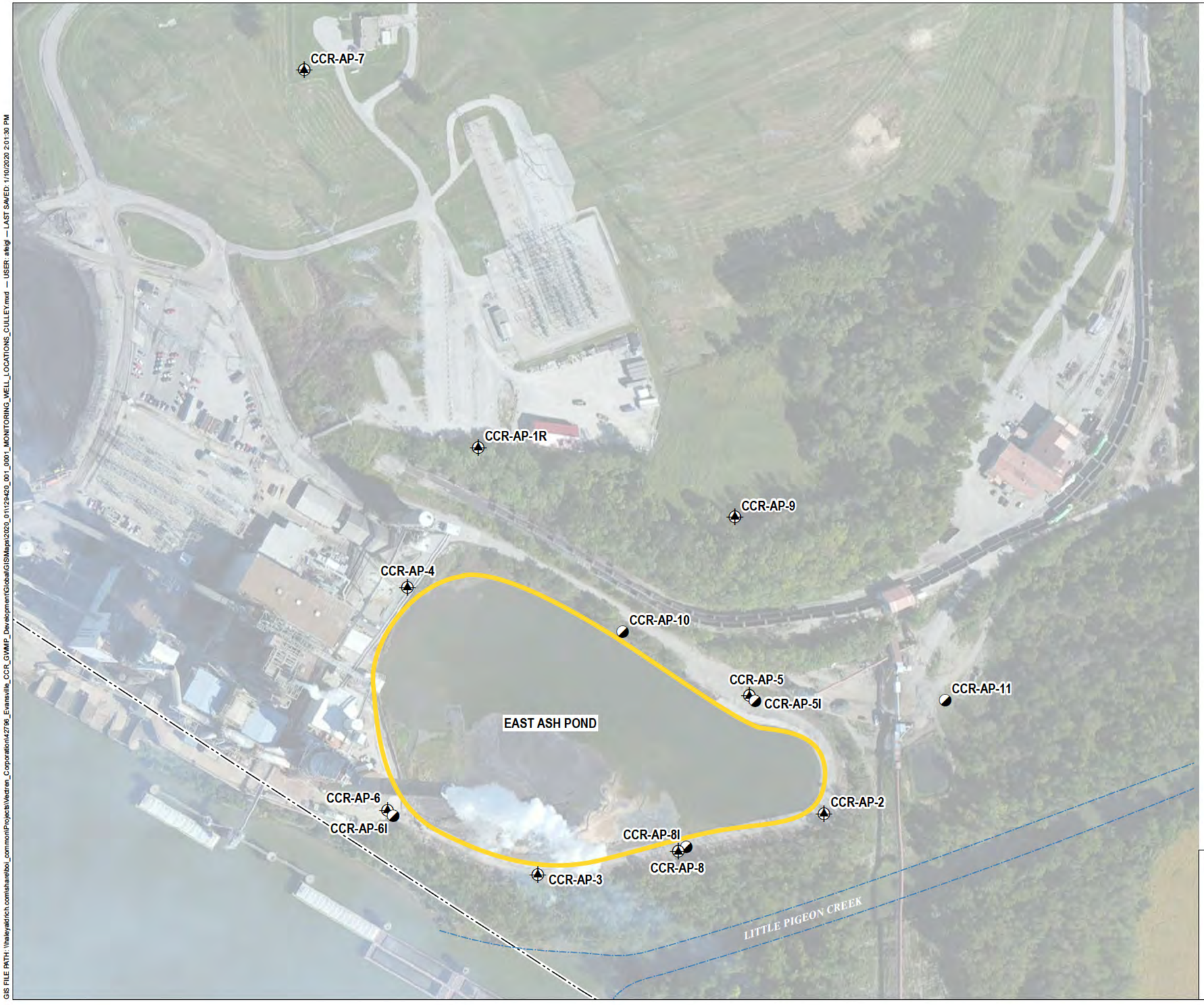
VP, Environmental & Corp Resp

Title

11/23/20

Date

Appendix E
Groundwater Monitoring Well Location



LEGEND

CCR-AP-11 MONITORING WELL

CCR-AP-6I NATURE AND EXTENT MONITORING WELL

APPROXIMATE UNIT BOUNDARY

APPROXIMATE PROPERTY BOUNDARY

NOTES

1. ALL LOCATIONS ARE APPROXIMATE
2. CCR COAL COMBUSTION RESIDUALS
3. AERIAL IMAGERY SOURCE: ESRI

N

0 220 440

SCALE IN FEET

HALEY ALDRICH

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
F.B. CULLEY GENERATING STATION
NEWBURGH, INDIANA

GROUNDWATER MONITORING WELL LOCATIONS

JANUARY 2020

FIGURE 1

GIS FILE PATH: \\haleyaldrich.com\share\boi_common\Projects\Vectren_Corporation\142796_Evansville_CCR_GWMP_Development\Global\GISMaps\2020_01\129420_001_0001_MONITORING_WELL_LOCATIONS_CULLEY.mxd — USER: sfeigl — LAST SAVED: 1/10/2020 2:01:30 PM

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 110
DOE Order No. 202-24-1

Department of Energy
Washington, DC 20585

Order No. 202-24-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Florida due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On October 9, 2024, Duke Energy Florida, LLC (Duke), an investor-owned utility, whose service territory includes electric customers in Florida, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." As of 4 PM EDT on October 9, 2024, Hurricane Milton is a Category 3 storm forecast to remain a major hurricane and expand in size as it approaches the west coast of Florida. The center is likely to make landfall along the west-central coast of Florida during the night on Wednesday, October 9, 2024, or in the early morning on Thursday, October 10, 2024, and move east-northeastward across central Florida through October 10, 2024. Hurricane Milton follows the landfall of Hurricane Helene in Florida on September 26, 2024, which resulted in over 230 deaths in the southeast United States and for which recovery and restoration efforts remain ongoing. As of 5:00 PM EDT on October 9, 2024, Florida was experiencing 118,000 outages related to the approaching Hurricane Milton, with the number increasing rapidly.

On October 7, 2024, President Biden declared that an emergency exists in the State of Florida and ordered Federal assistance to supplement State, tribal, and local response efforts due to the emergency conditions resulting from Hurricane Milton beginning on October 5, 2024, and continuing.

Duke has indicated that its service territory is being impacted by Hurricane Milton. Duke expects that Hurricane Milton will cause hurricane-force-gusts across the St. Petersburg/Tampa metropolitan region at the height of the storm overnight into early Thursday, October 10, 2024. Elsewhere, strong tropical-storm to near hurricane-force-gusts are projected to impact highly populated zones along the I-4 corridor served by Duke. The combination of damaging winds,

torrential rain and subsequent flooding, storm surge at the coast, and possible tornadoes, will result in major power outages, damaging distribution and transmission infrastructure, and threaten several generation stations along the path. Application at 1.

While many generating units in the Duke service territory continue to function adequately under these stressed conditions, several of Duke's generating units are expected to be forced to shut down due to facility limits on wind speeds and storm surge, as well as staffing issues caused by mandatory evacuations. Additionally, Crystal River Units 4 and 5 remain in forced outage from storm surge impacts from Hurricane Helene. Specifically, approximately 4,000 MW of generating units are currently offline and will remain offline during Hurricane Milton. Application at 2.

Additionally, several units at Citrus Combined Cycle, the subject of this Order, may be forced offline by conditions in its Title V operating permit. With projected outages and low demand, in order to keep the Citrus Combined Cycle units online, they would potentially need to operate at low load for an extended period of time, which could result in noncompliance with its Title V permit. If these units are brought offline due to these compliance requirements, they may not be able ramp up quickly enough to meet demand as load increases following power restoration, particularly in light of the amount of generation predicted to be offline due to hurricane impacts. For example, ramp-up times from a cold start could be eight or nine hours, and could be further delayed by pre-generation start-up checks. Additionally, shutting down also increases the risk or equipment failure, as well as the risk of water intrusion due to thermal and pressure gradient changes. If equipment fails or is damaged by Hurricane Milton, units may not be able to start without additional maintenance. In that case, Duke may have to declare an Energy Emergency Alert (EEA) Level 3 and institute rotating load shed. Such impacts would hinder post-hurricane restoration and recovery activities and overall grid reliability. Although Duke would attempt to mitigate such impacts through alternative generation as well as power purchases, it is unknown what will be available following Hurricane Milton and whether the necessary transmission infrastructure will remain for this purpose. Application at 2.

The Florida Reliability Coordinating Council, Inc. (FRCC), the Reliability Coordinator for Duke's service territory and others, filed a formal endorsement on October 9, 2024, of Duke's Application, specifically the need to continue operation of the Specified Resources in Application Exhibit A at low load operation to help reduce the likelihood of any firm load shedding during the hurricane event. FRCC Letter at 1. The endorsement explains:

> It is the FRCC's firm opinion that granting this relief request will provide an immeasurable benefit to this mission and in turn, the public served by the FRCC and its member entities. Allowing this relief will not only serve the reliability of [Duke's] service territory, but also the many local electric cooperatives served by [Duke] and other interconnected electric utilities and service providers.

FRCC Letter at 2.

Description of Mitigation Measures

Duke has indicated that it will attempt to keep the Citrus Combined Cycle units operating at a load level compliant with its Title V permit whenever possible, including attempting to sell power to keep load higher. Duke anticipates needing to continue these efforts through October 13, 2024. Subject to the exceptions included in this Order, Duke has committed to continuing to take such actions, including attempting to sell power, before operating any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations.

Request for Order

Duke requests that the Secretary issue an order immediately, effective October 9, 2024, through 00:00 EDT on October 13, 2024, authorizing "continued operation of the Specified Resources" in the Duke service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-24-1 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke to ensure maximum reliability on its system, and the ability of Duke to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current extreme weather event and its aftermath threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Florida and within the region demonstrate the need for the Specified Resources to contribute to system reliability.
- Duke's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the load resulting from the extreme weather event and its aftermath.

In line with the anticipated circumstances precipitated by Hurricane Milton, this Order is limited to the period beginning with the issuance of this Order on October 9, 2024, through 00:00 EDT on October 13, 2024. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. Duke anticipates that this Order may result in exceedance of emissions of Volatile Organic Compounds (VOC), specifically formaldehyde. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on October 9, 2024, to 00:00 EDT on October 13, 2024, in the event that Duke determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke anticipates in Florida during and immediately following this event, I direct Duke to dispatch such unit or units and to order their operation only as needed to maintain the necessary expected generation in the Duke service territory. Specified Resources are those generating units set forth on the Order 202-24-1 Resource List, which the Department shall post on www.energy.gov. Duke is directed to provide updates, if any, to Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 EDT on October 10, 2024.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for maintaining grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Duke shall exhaust all possible measures to run the Specified Units at a load level in compliance with permit requirements, including attempting to sell power. Duke shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. Duke shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By October 20, 2024, Duke shall report all dates between October 9, 2024, and October 13, 2024, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting

limits, including formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. Duke shall submit a final report by November 20, 2024, with any revisions to the information reported on October 20, 2024. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, formaldehyde, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; October 10, 2024; 4 hours; 04:00-08:00 EDT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, Duke shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to the Specified Resources in connection with any order issued by the Department pursuant to Section 202(c) of the Federal Power Act.

E. Duke shall take reasonable measures to inform affected communities where all Specified Resources operate that Duke has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows Duke to do. At a minimum, Duke shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of any Specified Resource covered by this Order. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by Duke with respect to the extreme weather event and will include a reference to the website posting required by the preceding sentence for further information. Duke shall describe the actions taken to comply with this paragraph in the

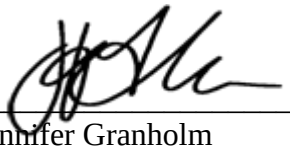
reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Duke shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on Sunday, October 13, 2024, with the exception of the reporting requirements in paragraph D. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:00 PM Eastern Daylight Time on this 9th day of October 2024.



Jennifer Granholm
Secretary of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 112
Witmeier 2024 Queue Cap Testimony

This document was published in full (including pages with the word "Confidential" beginning on page 39) on the website of the Federal Energy Regulatory Commission on December 13, 2024.

TAB A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF ANDREW WITMEIER

ON BEHALF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

November 21, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF
ANDREW WITMEIER

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Andrew Witmeier. I am the Director of Resource Utilization for the Midcontinent Independent System Operator, Inc. ("MISO"). My business address is: 720 City Center Drive, Carmel, IN 46032-7574.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined MISO in 2003 after graduating from Purdue University with a bachelor's degree in electrical engineering. I spent the first 17 years of my career in various positions in MISO Operations. During that time, I worked as a North American Electric Reliability Corporation ("NERC") certified system operator in scheduling, engineering, and as a reliability coordinator. I also led several groups within MISO Operations as a manager in engineering, reliability coordination, and seams administration. In January 2020, I was appointed to my current position.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS FILING.

A. As the Director of Resource Utilization, I am responsible for the administration of MISO's Generator Interconnection Procedures ("GIP"), which are set forth in Attachment X of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff" or "MISO Tariff").[1] I oversee MISO's generation interconnection queue, including the negotiation and execution of Generator Interconnection Agreements ("GIAs"), which are based on MISO's *pro forma* GIA set forth in Appendix 6 of the GIP. I also oversee the group that manages and processes generation retirement, generator replacement, and Surplus Interconnection Service requests for generators connected to MISO's Transmission System. I have been directly involved in the preparation and development of the current proposals.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony at the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket No. ER22-661-000 on issues related to MISO's generator queue reform and resource utilization and Docket Nos. ER24-340-000 and ER24-341-000 on additional issues related to MISO's generator queue reform and management.

II. OVERVIEW AND PURPOSE OF TESTIMONY

Q. ARE YOU SUBMITTING YOUR TESTIMONY ON BEHALF OF MISO?

A. Yes.

[1] Unless otherwise indicated in my Testimony, all capitalized terms used herein have the meaning as set forth in the Tariff or the proposed Tariff revisions, as applicable.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the updated Tariff revisions that MISO is submitting in this docket to refile certain urgent quantity improvements to the GIP. As further discussed below, MISO's filing in this docket contains two severable proposals. While these proposals are separate from each other, both should be implemented as soon as possible to ensure that MISO's generator interconnection queue can continue to operate in a just and reasonable manner in the face of severe challenges precipitated by an ongoing and unprecedented increase in the number and volume of Interconnection Requests in MISO. The proposed changes will make MISO's administration of the queue more efficient and will improve MISO's compliance with the GIP timing requirements.

Q. HOW WAS THIS NEW PROPOSAL DEVELOPED?

A. MISO developed this updated proposal through a broad and inclusive stakeholder process. This filing incorporates the extensive stakeholder input we received in the past several months and reflects the lessons we learned from our previous queue reform efforts, including the Commission's guidance in Docket No. ER24-341-000. As discussed in more detail below, we have addressed the specific suggestions and concerns identified in the guidance order and have provided extensive opportunities for all interested parties to comment during the stakeholder review process. The final proposal that MISO is submitting today incorporates many of the comments and recommendations we have received in the process.

Q. HOW IS THIS FILING DIFFERENT FROM THE NOVEMBER 2023 CAP PROPOSAL?

A. MISO adjusted the formula for determining the cap, how exemptions will fit within the cap structure, and the types of exemptions presented in the current filing. With respect to the cap formula, the current proposal responds to the Commission's directives and opts for a more balanced, much simpler approach that relies on the MTEP power flow model to run the interconnection studies as the basis for the cap formula. The proposed cap formula will be 50% of the non-coincident summer peak values for each study region from the power flow model that will be used to perform the queue studies.[2] This percentage was chosen based on analysis performed by MISO that showed when queue volumes continue to rise above 50%, more Network Upgrades are required to mitigate congestion caused by new Interconnection Requests, offsetting substantially more existing generation. The purpose of a cap is to establish a more realistic dispatch that includes existing generation with new Interconnection Requests. This improved dispatch should result in less Network Upgrades, which reduces costs and reduces the need for additional facility studies and should therefore lead to faster processing and less dropouts. In light of the Commission's Order in Docket Nos. ER24-340-000 and ER24-341-000, MISO significantly modified the exemptions from its prior proposal. First, MISO removed the RERRA exemption. After special consideration of the comments and concerns brought forth by stakeholders and the Commission and the unique needs of RERRAs, MISO has committed to address RERRAs

[2] *Queue Improvements Cap Proposal* (October 16, 2024), https://cdn.misoenergy.org/20241016%20PAC%20Item%2006b%20Cap%20Proposal%20(PAC-2023-1)653144.pdf.

in a separate, newly proposed Expedited Resource Adequacy Study ("ERAS") process.[3] This new process will expedite the approval process of new generation needed to address state resource adequacy goals.[4] Second, addressing the Commission's earlier concerns regarding uncapped exemptions, MISO updated its queue cap formula to note that approved exemptions will be included in the number of Interconnection Requests needed to reach the 50% cap number. Put another way, approved exemptions will count towards the total MW queue cap of a given region. Third, any exemption must be elected at the time the interconnection application is submitted. This ensures the efficient implementation of the processing of the exemptions, less volatility in establishing the queue cap, and increases the levels of communication between MISO and stakeholders regarding when the queue cap is met. Finally, MISO is modifying the Provisional Generator Interconnection Agreement ("PGIA") exemption to stipulate that the PGIA exemption must be requested at the time of application. MISO determined that mandating an executed PGIA made it extremely difficult for Interconnection Customers to utilize this exemption for the reasons outlined above. Additionally, Interconnection Customers with a requested PGIA have assumed additional risks when their request for PGIA is made. While they are similarly situated to Replacement Generating Facilities or ERIS to NRIS conversions, MISO addressed PGIA specific concerns, such as when an Interconnection Customer can revert to non-provisional status.

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[3] *See Expeditated Resource Adequacy Study (ERAS) Introduction* (November 13, 2024), https://cdn.misoenergy.org/20241113%20PAC%20Item%2009%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Introduction660245.pdf;.

[4] *See Expedited Resource Adequacy Study (ERAS) Workshop* (November 18, 2024), https://cdn.misoenergy.org/20241118%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop661622.pdf.

Q. PLEASE DESCRIBE WHY THE EXEMPTIONS, SITE CONTROL AND PAYMENTS ARE NOW REQUESTED WITH THE APPLICATION SUBMITTAL.

A. Following the Commission's Order on its first proposal, MISO reanalyzed its internal processes on how it would validate Interconnection Requests. MISO determined it was administratively inefficient to allow Interconnection Customers to retroactively request priority project status. Retroactive requests undermine the assertion that a project is truly a priority project. Retroactive requests can also unfairly game the limitation on a queue cycle. For example, under MISO's previous proposal, if a project learns that it will not be under the queue cap, then it could retroactively propose to enter into a PGIA in order to gain access to the next queue cycle. Under the previous proposal, that same project could later revert to non-provisional status with no penalty. Stakeholders expressed similar concerns. By adjusting the requirements for when an exemption must be declared and the requirements to maintain that exemption, MISO levels the playing field for all projects. These changes will necessitate that Interconnection Customers who want to make use of the PGIA exemption evaluate its project's feasibility and viability earlier in the process to determine whether they are willing to be bound by the PGIA commitments that make these projects more certain and justify their priority inclusion. This approach will allow MISO to efficiently process and prepare for a given Definitive Planning Phase ("DPP") Cycle. Additionally, MISO modified its proposal to notify its Interconnection Customers of the queue cap earlier in the process.

Q. PLEASE SUMMARIZE THE ADDITIONAL STAKHOLDER MEETINGS FOLLOWING THE ISSUES OF THE COMMISION'S REJECTION.

A. MISO re-engaged with the stakeholders and revised its initial cap proposal. The revised proposal was posted for stakeholder review and discussed in the Interconnection Process Working Group ("IPWG") and Planning Advisory Committee ("PAC") on multiple occasions. During these discussions, an alternative proposal ("Savion VPE proposal") was presented and subsequently voted on by stakeholders at the IPWG. Ultimately, the alternative proposal didn't receive enough votes to pass.

Q. PLEASE DESCRIBE THE BREAKDOWN OF THIS FILING.

A. MISO views the Queue Cap Proposal and the Exemptions to the Queue Cap Proposal as being two separate, but related, proposals included together in one filing for administrative convenience and Tariff version control. The Queue Cap Proposal is necessary and appropriate to address the unsupportable number of Interconnection Requests that MISO must process. It is a complete proposal in and of itself and does not depend on the approval of any of the exemptions to be complete or reasonable rate. While the Exemptions to the Queue Cap Proposal will necessarily depend on the acceptance of the Queue Cap Proposal, it is severable and a complete proposal. The Exemptions to the Queue Cap Proposal is intended as a standalone set of enhancements to the Queue Cap Proposal. While it is not necessary to make the cap function, the exemptions add independent value. Specifically, they allow the historically limited number of projects that have used PGIAs, sought ERIS to NRIS conversions, or sought to add additional interconnection service to a replacement facility to proceed directly into the next queue cycle in acknowledgement of the facts that these types of projects have proven highly certain given the level of commitment undertaken or the existing facilities. Even if the Commission determines the Exemptions to the Queue Cap Proposal does not adequately address the open access concerns identified

in its previous order, the state of the queue still necessitates a backstop queue cap to properly function, and the cap can function without the exemptions. I note that neither I nor my staff made any promises regarding whether the exemptions should be included in the cap filing or made any compromises to secure stakeholder support for the Queue Cap Proposal based on these exemptions. MISO commits to making a subsequent filing with the Commission to update the Tariff sheets to reflect the most up-to-date versions of the then-current Tariff provisions and within sixty (60) days of an order on each proposal is

Q. DID MISO ENGAGE THIRD PARTIES TO SUPPORT THE DEVELOPMENT OF THE PROPOSED REFORMS?

A. Yes. MISO hired Charles River Associates ("CRA") in early 2023 to perform an analysis of the MISO generator interconnection queue and to recommend changes to the process that would improve the quality of projects entering the queue, as well as MISO's ability to provide timely and consistent study results. CRA provided its findings in the stakeholder process and their final report is included as Exhibit 1 to my testimony ("CRA Report").

Q. DID MISO ADOPT ALL OF CRA'S RECOMMENDATIONS IN THIS PROPOSAL?

A. MISO adopted a significant number of CRA recommendations, with some adjustments. MISO adjusted the Proposals based on guidance of the Commission's Order in Docket No. ER24-341-000. These final proposals reflect the collaborative input from MISO, its stakeholders, and the additional CRA analysis on the need for a cap. An example of the CRA recommendation that was not included was to consider an individual developer cap on proposed projects, in addition to the overall MW value cap. The intent of this CRA recommendation was to provide a protection mechanism such that smaller developers are

not crowded out of the process by larger developers. This concept potentially could be necessary at some point in the future, but at this time MISO believes there is insufficient evidence to support a per-developer cap in the Queue Cap Proposal as needed.

Q. HOW DO THESE FILINGS RELATE TO MISO'S COMPLIANCE OBLIGATIONS UNDER ORDER NO. 2023/2023-A?

A. At the time of this submission, MISO submitted its Order No. 2023-2023-A compliance filings pursuant to the independent entity variation requirements set forth in Order No. 2003.[5] If the Commission accepts the proposed revisions, they will become part of the MISO Tariff. The proposal is submitted as a necessary independent entity variation to MISO's compliance with Order No. 2023-2023-A.

III. THE CURRENT STATE OF THE MISO QUEUE AND THE CONTINUED NEED FOR A CAP

Q. PLEASE DESCRIBE MISO'S INTERCONNECTION QUEUE PROCESS.

A. MISO's generator interconnection queue process generally follows the Commission's *pro forma* Large Generator Interconnection Procedures ("LGIP"), with changes and improvements adopted over the years pursuant to the Commission's independent entity variation. The current framework was put in effect in January 2017 as a result of extensive stakeholder driven reforms, which implemented a novel three-phase DPP structure to study Interconnection Requests, which since has been successfully adopted in some other regional transmission organizations ("RTOs"). MISO uses clusters to study

[5] *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

Interconnection Requests, with each calendar year producing one or two study clusters, known as "cycles." The clusters are studied on a subregional basis and, as I previously noted, MISO currently has five interconnection queue study regions.

Q. PLEASE EXPLAIN HOW THE THREE-PHASE DPP PROCESS WORKS.

A. The DPP structure provides for a sequential process to study Interconnection Requests in the queue. MISO conducts one System Impact Study ("SIS") in each of the three DPP Phases (*i.e.*, Preliminary SIS in DPP Phase I, Revised SIS in DPP Phase II, and Final SIS in DPP Phase III) to account for project withdrawals and to refine and update the analysis. Facilities Studies are conducted in DPP Phases II and III. The DPP process also includes three milestone payments—M2, M3, and M4, and provides for two designated off-ramps—Interconnection Customer Decision Points I and II ("Decision Points"). The first milestone payment, M2, is fixed at $8,000 per MW of Interconnection Service requested and is payable at entry into the queue. The second milestone, M3, is equal to the greater of twenty (20) percent of the amount of Network Upgrades identified in the Preliminary SIS less the amount previously posted as M2 or $1,000/MW. M3 is due at the end of Decision Point I. The third milestone, M4, is equal to 30 percent of the amount of Network Upgrades identified in the Revised SIS less than the amount previously posted as M2 and M3 payments. M4 is due at the end of Decision Point II. These milestones may be partially refundable upon withdrawal depending on the time of withdrawal and on whether they increase the Network Upgrade cost to other Interconnection Customers in the same cycle pursuant to a calculation of financial harm to other Interconnection Customers, as set forth in Section 7.8 of the GIP (*i.e.*, the "harm test"). The GIP also provides for penalty-free withdrawals in specified circumstances, as set forth in Section 7.6.2.4 of the GIP, less any

Automatic Withdrawal Penalty that was established in reforms approved by FERC in January 2024.6 The two off-ramps, Decision Points I and II, each last fifteen (15) Business Days and allow Interconnection Customers to review the study results from the most recent phase, pay the applicable milestone, and decide whether to proceed to the next DPP phase or withdraw from the queue.

Q. PLEASE DESCRIBE THE CURRENT STATUS OF MISO'S GENERATOR INTERCONNECTION QUEUE.

A. As of October 30, 2024, MISO's generator interconnection queue contained 1,706 active Interconnection Requests comprising of nearly 312 GW of proposed new generator interconnection capacity, which is a considerable backlog. This backlog is spread over all five queue study regions and includes queue cycles going back to 2019. It should be noted that when MISO previously made this cap filing in November of 2023, MISO's generator interconnection queue contained 1,371 active Interconnection Requests comprising nearly 236 GW of proposed new generator interconnection capacity. In contrast, MISO's peak load is only 127.1 GW and, as of December 2023, 191 GW of functioning total installed generation capacity already exists in the MISO Region.

Q. HOW DOES THE CURRENT QUEUE SIZE COMPARE TO PRIOR YEARS?

A. The current queue size is extraordinary and unprecedented. The most recent queue cycle, DPP-2023, alone is 124 GW. The two immediately preceding cycles, DPP-2022 and DPP-2021, were 170.8 GW and 76.8 GW, respectively. In contrast, the two cycles that started in 2017 following the implementation of the three-phase DPP process, DPP-2017-FEB and

6 *Midcontinent Indep. Sys. Operator*, 186 FERC ¶ 61,054 (January 19, 2024).
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DPP-2017-AUG, were only 30.7 GW, which generally is in line with the average queue cycle size in 2014-2016. It is important to note that the queue reforms approved by FERC in January 2024 did result in lower number of submitted projects. DPP-2023 had 30% less Interconnection Requests submitted than the amount of DPP-2022. However, the 124 GW in DPP-2023 is still as large as MISO's typical summer peak load. This shows that the previous reforms were not enough to facilitate a more efficient queue, and a MW cap is still necessary.

Q. WHAT IS THE CURRENT FUEL PROFILE OF THIS PROPOSED GENERATION?

A. Virtually all the proposed generating capacity in the latest queue cycles involves intermittent and weather-dependent resources, with solar facilities accounting for the lion's share of those.

Q. WHAT IS THE PERCENTAGE OF PROPOSED GENERATION IN THE MISO QUEUE THAT USUALLY GETS BUILT?

A. The CRA Report analyzed queue withdrawals in the latest queue cycles. *See* Exhibit 1 at 7-10. In the most recent completed cycles at the time of the report, DPP-2017-FEB, DPP-2017-AUG, and DPP-2018-APR, nearly 70% of the total generation capacity that entered these cycles was eventually withdrawn. *Id*. at 8-9. The remaining approximately 30% got their GIAs, but the actual MWs of generating capacity that will be constructed and energized will be less than 30% due to financial and construction stage challenges. Some of these GIAs have already been terminated, and various delays impacting some of the remaining GIAs will reduce the number of projects that achieve commercial operation still further.

Q. DO YOU EXPECT THE CURRENT QUEUE TRENDS TO CONTINUE?

A. Yes. I expect the queue to continue to grow in the next several years, with the bulk of the new proposed generating resources continuing to be intermittent and weather dependent.

Q. WHAT IS THE BASIS FOR YOUR EXPECTATION?

A. I attribute this trend to growing customer demand for renewable generation, the considerable financial incentives for renewable generation implemented in the *Infrastructure Investment and Jobs Act of 2021* and the *Inflation Reduction Act of 2022*,[7] and the backbone transmission MISO has approved, and plans to approve, through our Long Range Transmission Planning ("LRTP") effort. In July 2022, the MISO Board of Directors approved the first tranche of LRTP projects worth an estimated $10.3 billion of regional transmission facilities, which will provide access to the MISO grid for many new renewable resources. MISO anticipates a second tranche of projects to be approved in December 2024, currently estimated at $21.8 billion and known as LRTP Tranche 2.1. These contributing factors make a growth in Interconnection Requests very likely, and it is critical to implement the proposed reforms to ensure that MISO can manage the continuing growth.

Q. IF THE MAJORITY OF INTERCONNECTION REQUESTS IN THE QUEUE WITHDRAW, WHY IS THE CURRENT QUEUE GROWTH PROBLEMATIC?

A. The increasing number and volume of speculative Interconnection Requests in the queue strains MISO's resources and ability to process Interconnection Requests in accordance with the Commission's timing requirements and causes delays in the completion of required Interconnection Studies. This leads to increasing withdrawals, less certain DPP

Phase I and II study results, and ultimately, uncertainty and delays for all Interconnection Customers in the queue. Currently, queue delays are one of the largest contributing factors that negatively impact Interconnection Customers' ability to timely execute a GIA and, potentially, receive timely capacity accreditation under MISO's Resource Adequacy construct. Although cluster studies allow for multiple Interconnection Requests to be studied together, many administrative tasks required to process the queue are performed on an individual Interconnection Request basis. Such tasks include application processing to review modeling data, Site Control, and financial security and certain other tasks. Also, each Interconnection Request usually has one POI that requires its own individual studies, and each GIA is negotiated and executed individually.

Furthermore, independent from these timing challenges, the growth of the interconnection queue jeopardizes the ability of Interconnection Customers to receive study results that reflect actual system impacts, and the costs needed to mitigate them, especially in earlier phases of the DPP. To capture the actual impact of an Interconnection Request on the Transmission System, MISO must study that Interconnection Request at its full output, according to fuel-based dispatch assumptions, to establish the Network Upgrades needed to accommodate that request. Because a project is allowed to operate up to the service levels specified in its GIA, failure to capture the impacts of operating at such a level would artificially understate the impact of that project. This, in turn, can lead to overloads and other reliability cost problems if not mitigated, and cause cost shifts if the mitigations are identified in later studies for other projects. Thus, it is important to capture the full impact of a proposed project in an Interconnection Study. However, this becomes increasingly challenging when the amount of generation proposed in a queue cycle begins to exceed

projected peak load. Proposed generating facilities do not exist in a vacuum on MISO's system. In addition to what is proposed in a given queue cycle, there is existing generation already in commercial operation on the Transmission System and higher queued projects whose output must be accounted for in studies for new Interconnection Requests. When the total of this generation far exceeds load, MISO must use assumptions in order to develop a valid mathematical solution that will allow for a model that studies new generation at its authorized output while still sinking that power in the MISO region. MISO has some limited flexibility in model building to address these problems. However, the larger the queue size, the more aggressively MISO must adjust its assumptions to allow the model to solve (*i.e.*, to balance generation and load). Past a certain point, these assumptions begin to diverge sufficiently from reality and the model is no longer modelling how MISO's Transmission System and generation resources are expected to behave. The results of a study built on such models have diminished value because some existing generation will continue to dispatch well above the artificially lowered assumptions resulting in reliability issues on the Transmission System that were not studied. This, in turn, will require new studies in the interconnection process or in annual transmission planning studies resulting in potential cost shifts to future Interconnection Requests or to load, which creates risks and cost uncertainty for both existing and future projects, can lead to reliability issues on the Transmission System, and ultimately delays in deploying new generation. In short, assumptions diverging from expected conditions is a necessary result of study clusters that are too large to study under realistic system conditions, particularly when populated with increasing numbers of speculative Interconnection Requests. And, while Interconnection Customers will receive some "results" from these studies, those

results have a diminished value and, will ultimately cause more risk to the Transmission System and Interconnection Customers than study results based on cluster sizes that allow for realistic assumptions to be used.

Q. HAS MISO ATTEMPTED TO ADDRESS THESE CHALLENEGES WITHOUT LIMITING ITS QUEUE SIZE ?

A. MISO is continuously striving to improve its GIP. Following the introduction of the three-phase DPP in 2017, MISO made several targeted efforts to improve various aspects of the DPP process, such as milestone and penalty provisions, Site Control requirements, expedited processing options and other improvements, as summarized in the transmittal letters accompanying the MISO filings in the dockets. Nonetheless, no material changes have been made to the milestone amounts and penalty-free withdrawal provisions since 2017. Accordingly, the new challenges that have recently arisen require an urgent response and change to those GIP requirements. Additionally, MISO submitted and received approval for a set of queue reforms in early 2024 regarding increased financial payments and penalties along with increased site control requirements.

D. TRANSITION PROVISIONS

Q. IS MISO PROPOSING ANY TRANSITION PROVISIONS FOR THE REFORMS INCLUDED IN THE GIP IMPROVEMENTS FILING?

A. Yes, the transition provisions are included in proposed section 5.11 of the GIP. Generally, the proposed reforms will apply only to Interconnection Requests submitted in study cycles with application deadlines after the effective date of the reforms, starting with the DPP 2025 cycle. All preceding cycles will be exempt from the proposed changes.

IV. THE NEW CAP FILING

Q. PLEASE DESCRIBE THE UPDATED PERCENTAGE-BASED CAP MECHANISM.

A. The percentage-based load nature of the cap ensures that the studies are appropriately scaled to consider existing generation, new Interconnection Requests, and the load MISO serves while still enabling competition. The new queue cap formula is noted below:

*MISO study region cap = 50% * study region non-coincident summer peak*

The proposed cap formula will be 50% of the non-coincident summer peak values for each study region from the power flow model that will be used to perform the queue studies. MISO will use the most recent available MTEP model series. Open access is maintained as Interconnection Requests that are included in the cap are based on the timing of their request. This formula will ensure more reasonable study volumes and subsequently result in more certain study outcomes. The new proposed cap formula differs in three ways from the rejected cap formula. First, the new proposed cap formula uses non-coincident summer peak values while the original cap formula used non-coincident shoulder peak values. Second, the old cap formula utilized the Pmin value as floor to which existing generation can be turned down to accommodate to generation. The new cap formula does not. Finally, the old cap formula adjusted for estimated withdrawals and exemptions. MISO will review the need for a queue cap after three (3) years.

Q. WHY IS IT REASONABLE TO REQUIRE A 50% QUEUE CAP?

A. The 50% queue cap is reasonable because it allows MISO to balance the appropriate level of the interconnection queue size to ensure that Interconnection Requests are processed efficiently, increasing certainty for active projects and reduces the risk of future cost shifts,

while also addressing the base load needs of each study region. After numerous rounds of internal analysis, MISO determined that 50% of the non-coincident peak best strikes that balance. The analysis entailed performing iterative model builds at a reduced non-coincident peak value until the model could be built and solved without the need for Backbone Network Upgrades or needing exports to neighboring systems. This threshold was met at 50%. Backbone Network Upgrades are an indication that the model, before taking any contingencies, is in such a state that the power flow can't be solved without the addition of Network Upgrade(s). Typically, this is an indication of voltage collapse. Similar, exports to neighbors are indication of further Affected System costs. The internal analysis recommended that the appropriate level of the queue cap as well would be 50%**.** This would balance out the backbone upgrades to a reasonable level where it is appropriate to obtain a usable model and run the DPP studies from. MISO provides the results below based on that internal analysis:

Power flow model	**Total GW of Queue Projects**	**% of Non-Coincident Peak Load**	**Backbone Network Upgrades**	**Export to Neighbors (GW)**
2022 Cycle test cases	67.6	50%	0	0
2022 Cycle test cases	80.9	60%	0	0
2022 Cycle test cases	84.3	63%	0	10.2
2022 Cycle test cases	90.9	68%	1 Transmission line	12.2
2022 Cycle test cases	95.9	72%	1 Transmission line	15.0

2022 Cycle Kickoff	142.0	106%	21.5 GVAR of voltage support	6.4
2022 Cycle Prescreen	177.0	132%	3 Transmission lines 42.5 GVAR of voltage support	10.3

As noted in the chart, while the 60% test case did eliminate the need to make Backbone Network Upgrades under the previous formula, MISO also accounted for shoulder peak load and Pmin evaluation, which are no longer accounted for in the newly proposed queue cap formula. Based upon this evidence, MISO elected to move forward with the 50% cap value. This new formula represents a balance between MISO's need to efficiently manage the queue while also addressing regional load needs and open access concerns.

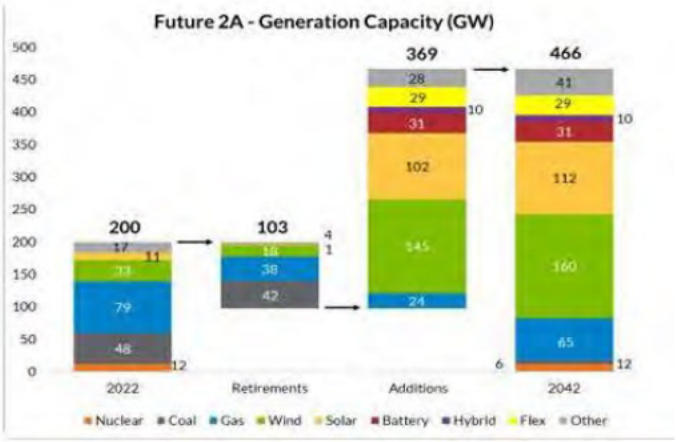
Q. WHY ARE THE PROPOSED CAP CHANGES STILL NECESSARY AND URGENT GIVEN THE EARLIER APPROVED QUEUE REFORMS?

A. While MISO noted that the increased GIP financial commitments and penalties along with updated site control evidence requirements that were approved in early 2024 resulted in a 30% reduction of "uncertain" interconnection applications from the previous cycle, it still represents a large number of projects for the team to study. Adding in the 2023 study cycle, MISO's current interconnection queue is sitting at roughly 312 GW. To put this into more context, MISO's all-time system peak load is 127 GW. Even with notable reductions of interconnection applications, the current interconnection service proposed in the queue is more than twice the all-time system peak load. This only further demonstrates purely qualitative improvements do not sufficiently increase in the queue size and ability to efficiently manage that queue. A MW limitation on individual interconnection queue

cycles will ensure that MISO can continue to produce more realistic resource dispatch, models, reduce queue timelines and produce lower Interconnection costs and therefore improving the success rate of the Queue, thereby increasing overall certainty in the interconnection queue. Additionally, MISO notes that the application portal is currently open and available for projects to be submitted into the next available study cycle; the cap is needed urgently to ensure that the appropriate balance of interconnection requests is processed in that study cycle.

Q. PLEASE DESCRIBE HOW THIS NEW PROPOSED CAP ADDRESSES THE COMMISSIONS EARLIER CONCERNS REGARDING FUTURE RESOURCE ADEQUACY NEEDS?

A. MISO re-engaged with its stakeholder to develop a proposal that would adequately address future adequacy needs. Per FERC's guidance, MISO reviewed the Future Planning Scenarios developed in conjunction with the Transmission Planning process("Futures"). MISO calls these scenarios "Futures," and they help MISO envision a set of possible resource adequacy outcomes up to twenty (20) years in the future. The scenarios establish a bookended range of economic, policy, and technological possibilities—such as load growth, electrification, decarbonization, renewable energy levels, generator retirements, fuel prices, and generation capital costs. The Futures hedge uncertainty by utilizing stakeholder information, policy direction, industry trends, and capacity expansion modeling to create the forecasts. Futures are updated with new or changing information. In reviewing the Futures 2A Planning Scenario, it was noted that 248 GW of Net Additions would be needed in the years 2025-2042 (17 years):



Taking this into account, MISO compared how the cap would impact this forecasted need.

Active Interconnection Requests in the Queue8	321 GW
Assumed completion rate of 21%	67.4 GW
Proposed Queue Cap	68 GW
Per Year additions (21% completion rate)	14.3 GW

Per the CRA report, using a historical completion rate of 21%, MISO estimates per year additions of 14.3 GW. From 2025 to 2042 and adding to the existing active Interconnection Requests already in the queue, this equates to 310 GW. Based on this analysis MISO believes there will be adequate throughput even with the cap to meet our future Resource Adequacy needs even with a queue cap of 50% of the non-coincidental peak load.

Q. PLEASE DESCRIBE HOW THIS NEW PROPOSED CAP FORMULA ADDRESSES THE COMMISSIONS EARLIER CONCERNS REGARDING EXEMPTIONS?

A. While limited in use given their inherent nature that minimize their submittals, MISO has found that projects related to increases in replacements, ERIS to NRIS conversions and PGIAs tend to reflect a greater commitment of the Interconnection Customer to the project and a lower withdrawal rate, leading to a greater level of certainty, given they are comprised of instances where an Interconnection Customer seeks to add incremental new service to an existing generating facility or have committed to a higher level of financial commitment. Given this criterion of existing generation facilities, MISO anticipates the continued limited use of these exemptions based on the inherent practical nature of these products that have historically limited their submittals. Additionally, in rejecting MISO's initial cap filing, citing the RERRA exemption, FERC noted an "uncapped exemption" potential that might undermine the benefits of having a cap in place. MISO ultimately found that the RERRA exemption engendered strong criticism from the stakeholders and the Commission, and the filing was ultimately rejected. Under the current proposal, MISO is amending Section 4.1.2 of Attachment X to remove the RERRA exemption. MISO has recognized that this as a more distinct queue issue that should be addressed in a separate filing. MISO has committed to working on addressing the needs of RERRA entities through a newly proposed ERAS process that will expedite the approval process of new generation needed to address resource adequacy. Furthermore, MISO has updated the cap formula to note that approved exemptions will be included with all projects that are used to meet the cap limit.

Q. DID CRA RECOMMEND A QUEUE CAP?

A. Yes. In fact, the CRA Report recommends two separate caps: (1) a queue cap per cycle; and (2) a per developer cap. *See* Exhibit 1 at 17-18. The CRA Report views a queue cap as a critical remedy to address the challenges outlined in my testimony. CRA recommended that MISO determine the level of the queue cap as well as its application across study regions, queue cycles and potentially individual entities. *Id*. at 17. The CRA Report further suggested that the following criteria could be considered in designing an appropriate queue cap: (1) peak load and forecasted peak load, (2) installed capacity, guaranteed additions, and expected retirements, and (3) reliability and resource adequacy. *Id*. at 18.

Q. WHAT ARE THE BENEFITS OF A STUDY CYCLE CAP?

A. The proposed cap will ensure that Interconnection Study results are based on a more realistic dispatch, thereby removing the need for prohibitively expensive and unrealistic Network Upgrades. Currently, Interconnection Customers receive realistic and informative study results only after enough projects exit the queue to achieve a realistic dispatch. The proposed cap will ensure more realistic and informative study results at an earlier point in the study process, without the delays and uncertainty caused by withdrawals after studies are performed with unrealistic Network Upgrade assumptions. The cap benefits Interconnection Customers by providing better cost estimates and a timelier study process. As discussed above, the cap also will provide benefits to the engineers performing these studies by improving their ability to solve these complex models and will reduce the amount of unnecessary engineering analyses, which are performed on a study model using unrealistic assumptions.

Q. WHERE WILL THIS CAP FORMULA BE STATED?

A. MISO will put the queue cap formula in the Tariff. In addition, MISO will post a report to its website prior to each study cycle describing the cap calculation and results.

Q. WILL MISO USE THE SAME FORMULA FOR POST-2025 QUEUE CYCLES?

A. MISO will continue to work with stakeholders to determine if the calculation should be modified for future cycles. MISO purposely used a simple calculation that more than adequately meets regional load needs. MISO also has committed to revisiting its cap-related Tariff provisions in three (3) years. MISO is willing to either provide an informational report discussing the effectiveness of these provisions after the third cluster study cycle or propose changes in a subsequent FERC filing based on the accumulated experience.

Q. HOW WILL MISO PROCESS APPLICATIONS ONCE THE CAP IS ESTABLISHED?

A. Once the cap amount has been calculated and posted, MISO will process the applications using a serial "first-come, first-served" approach based on when the applications were queued during the open application window. MISO will subsequently review the interconnection applications until the cap amount is reached. This process will provide an incentive to submit an Interconnection Request earlier in the open application window as opposed to right up until the application deadline as is often the case today. In addition, this process will have the added effect of "flattening the curve" for application submittals, *i.e.*, the projects would enter the queue when they are ready rather than wait until the last moment, thereby allowing MISO to manage the study cycle more efficiently. Meaning we expect projects to enter the queue when they are ready and will meet all necessary

requirements to secure their spot. MISO recognizes that this flattening of the curve will not hold true for the 2023 cycle, as it is expected that most applications will be submitted on the first day that MISO opens the web-based application tool to accept new applications.

Q. CAN YOU PLEASE EXPAND ON WHAT HAPPENS TO THOSE INTECONNECTION REQUESTS THAT FOUND TO BE "OVER THE CAP"?

A. Interconnection Requests that are processed after the cap has been met will continue to be evaluated by MISO to ensure they are valid requests, including necessary items such as milestones, Site Control, and modeling data. Once approved as valid, these Interconnection Requests will remain in the queue and will be studied in the next available queue cycle. Therefore, all Interconnection Customers, even those that are "above the cap", have comparable access to the interconnection process. A subset of the Interconnection Requests, i.e., those submitted closest to the time when the cap was met, can potentially replace projects that withdraw up to 30 days before the start of the DPP process. If a project that was under the cap withdraws, then MISO will pull the first project in the next cycle forward. This will be done up until the model needs to be built for the pre-screening analysis, which is 30 days before the start of the DPP process. This will allow 15 days to develop the model and post the pre-screening results, and then another 15 days for Interconnection Customers to review the analysis and determine if they should withdraw or remain in the queue and be included in the DPP process. Any dropouts that occur between the window when the pre-screening model is being developed and the start of the DPP process will not be replaced.

Q. CAN INTERCONNECTION REQUESTS IN THE QUEUE THAT ARE WAITING FOR THE NEXT CYCLE BE MODIFIED?

A. Yes, these Interconnection Requests will be able to make all the modifications allowable per section 4.4 of the GIP, which could include, but are not limited to: POI changes, MW reduction, removal of one fuel source for hybrids. Once these Interconnection Requests are included in a DPP study cycle, any changes will be evaluated as a potential material modification per Section 4.4.

Q. WILL DEVELOPERS KNOW THE MAXIMUM AMOUNT OF MEGAWATTS THAT CAN BE SUBMITTED IN A GIVEN QUEUE CYCLE?

A. Yes, the MW value for each DPP study cycle will be posted on the MISO public website at least ten (10) Business Days prior to the application deadline of that Definitive Planning study cycle. Additionally, MISO will post an associated whitepaper to the MISO public website to inform stakeholders how the cap was developed and set. It should be noted that as part of this process, MISO will be re-evaluating the formula prior to each study cycle, including the cap amount and the associated margins. There will be no cap on the number of individual requests any Interconnection Customer can submit. All applications will be evaluated against the cap on a "first come, first served" basis. This could result in an Interconnection Customer having a higher percentage of projects within any given queue cycle than another. If MISO determines this could create an unfair advantage over other Interconnection Customers, then MISO will develop an individual cap per Interconnection Customer and will file that tariff change with FERC for future queue cycles.

Q. IS MISO PROPOSING ANY EXEMPTIONS FROM THE QUEUE CAP?

A. Yes. MISO recognized in the early stages of development of its queue reform proposals the importance for a narrow set of Interconnection Requests to be included in a cycle if they already have an existing Generating Facility or Interconnection Service in place or otherwise exhibit a high level of certainty. These proposed exemptions are set forth in Section 4.1.2 of the GIP and include: 1) Interconnection Requests involving an increase in the capacity of an approved Replacement Generating Facility; (2) Interconnection Requests involving a conversion of ERIS into NRIS; (3) Interconnection Requests involving a Generating Facility with a requirement to request a PGIA. MISO initially proposed that these projects be exempt from the queue size limitations and other aspects of the initial proposal. In consideration of the concerns highlighted by the Commission, these projects will no longer be exempt from the queue cap limitations. However, as described herein, these projects will be exempt from certain requirements that will allow these exemptions to receive first access to the cycle for which it applies. Exemption requests must be submitted with their application submittal.

Q. PLEASE EXPLAIN THE REPLACEMENT FACILITY EXEMPTION.

A. Under the Tariff, Replacement Generating Facility requests generally are processed outside the interconnection queue. One exception to this process is when a Replacement Generating Facility requires Interconnection Service (in MW) in excess of that of the Existing Generating Facility that is being replaced. In such instances, the Replacement Generating Facility is allowed to generate up to the existing Interconnection Service of the Existing Generating Facility. However, an Interconnection Request associated with the excess MW value must proceed through the regular DPP cycle procedures. The proposed

exemption is for such excess capacity requests. Such requests are highly valuable to the MISO Transmission System because they are certain: the Replacement Generating Facility was already approved through the replacement process and exists under an executed replacement GIA.

Q. PLEASE EXPLAIN THE ERIS TO NRIS CONVERSION EXEMPTION.

A. The Tariff allows Interconnection Customers to convert their ERIS to NRIS, which is a higher level of Interconnection Service. The conversion requires submission of an Interconnection Request and proceeding through the queue. MISO proposes to exempt such "NRIS conversion" Interconnection Requests from the cap. The rationale is similar to that for the Replacement Generating Facility exemption discussed above. The Interconnection Request seeking conversion already has an executed GIA and as such, are highly valuable to the MISO Transmission System.

Q. PLEASE EXPLAIN THE PGIA EXEMPTION.

A. MISO's Tariff currently includes a process that allows its Interconnection Customers to enter into a PGIA before the end of the DPP cycle. The PGIA allows limited operation, based upon the results of available studies. This option allows an Interconnection Customer with a ready project to connect to the MISO Transmission System and inject power into the grid before the completion of all studies. The potential downside of the PGIA is that Interconnection Customers assume the risk of interconnecting prior to the completion of Network Upgrades being identified through the DPP process. Because Interconnection Customers with a requested PGIA have assumed additional risks and commit to proceeding through the DPP cycle regardless of the potential costs of Network Upgrades, MISO views these types of Interconnection Requests are as certain as existing

generation—so long as the ability to revert is limited. Unlike MISO's current PGIA process, which allows reversion from provisional to non-provisional status, Interconnection Customers that claim this exemption will forfeit its ability to revert with no consequences. Any Interconnection Customer that elects to proceed under the PGIA exemption and reverts back to non-provisional status will lose all monies and will forfeit its queue position. This exemption is available to any Interconnection Customer willing to assume PGIA risks, thus allowing an exception for Interconnection Customers who are willing to make commitments that a reasonable developer would not undertake for an uncertain project.

Q. PLEASE EXPLAIN WHY THE RERRA EXEMPTION WAS REMOVED FROM THIS UPDATED CAP FILING.

A. In early 2024, MISO and its stakeholders embarked on a joint effort to address the challenges introduced with the RERRA exemption. MISO engaged in discussions with stakeholders to identify the challenges associated with the implementation of the RERRA exemption for the cap. MISO identified several concerns with the original RERRA exemption process. First, MISO was concerned with how to limit the size of RERRA exemptions. The RERRA exemptions, unlike the included exemptions, posed a particular risk to diminishing the value of the cap. Second, multiple stakeholders brought forth comments regarding the standardization of format and processing of the RERRA exemptions. Third. MISO further recognized this as a more distinct queue issue that should be addressed in a separate process. There is a fundamental necessity for a short-term generator interconnector product to handle direct urgent resource adequacy needs for the states within the MISO system. Due to these challenges, MISO removed the RERRA

exemption from the current filing. However, the importance of RERRAs to the MISO Transmission System is not lost on MISO. To better respond to the unique needs of RERRAs, MISO will work with stakeholders on a separate, concentrated effort to address the unique resource adequacy needs of a RERRA. MISO has committed to working on addressing the needs of RERRA entities through a new ERAS process that is being developed with stakeholders now and will more comprehensively address the approval process of new generation needed to address resource adequacy.

VI. STAKEHOLDER PROCESS

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS USED TO DEVELOP THIS PROPOSAL.

A. MISO engaged in an extensive stakeholder process throughout the development of its updated queue cap proposal. MISO obtained feedback through the PAC and the IPWG, conducted dozens of calls with stakeholders across the MISO sectors, and receiving multiple rounds of formal and informal written feedback. During the stakeholder process, MISO considered the advantages and disadvantages of multiple approaches for addressing the identified challenges and risks, collaborating with stakeholders on identifying areas where flexibility could be increased. MISO revised its initial proposal considerably, incorporating the input received.

The key milestones of the stakeholder process were as follows:

- January 30, 2024: MISO provided an update to the IPWG regarding FERC's response on MISO's GIP Improvements and Cap filings, along with next steps.
- July 23, 2024: MISO presented several updates to the cap proposal to address FERC concerns with the original filing at the IPWG

- September 3, 2024: MISO provided refined proposal and responded to feedback at the IPWG.
- September 30, 2024: MISO held a special IPWG workshop to review the current proposal and answer stakeholder questions
- October 16, 2024: MISO presented a final package of reforms at the PAC. MISO also introduced its Expedited Resource Adequacy Study proposal.[9]

Q. WHAT WAS MISO'S RESPONSE TO CONCERNS AND RECOMMENDATIONS FROM STAKEHOLDERS?

A. Stakeholders asked MISO to justify a rationale for the 50% limitation, with some expressing concern that this cap would "arbitrarily" reduce the number of projects that can compete. MISO understands these concerns but notes that the rationale for selecting 50% is to ensure a balance of supply to demand while also addressing the queue administration difficulties MISO faces due to the volume of Interconnection Requests. Without limiting the amount of Interconnection Requests, the interconnection queue will continue to grow at an unsustainable rate, slowing study processes and making results less accurate. MISO supports many of the objectives of the alternative Savion VPE Proposal and is committed to working with stakeholders to incorporate elements of that proposal to meet those objectives.

Q. IS MISO STILL CONINUING TO IMPROVE QUEUE COORDINATION WITH INTERCONNECTION CUSTOMERS AND TRANSMISSION OWNERS?

A. Yes. In addition to the proposed Tariff changes, MISO has multiple efforts underway to enhance the queue experience. These transparent initiatives will facilitate enhanced

9 ERAS Workshop Citation

Interconnection Customer workflow throughout Interconnection Request lifecycle. MISO is coordinating the development of these enhancements through the stakeholder process.

VII. CONCLUSION

Q. IN YOUR OPINION, ARE MISO'S FILINGS JUST AND REASONABLE?

A. Yes. This updated cap Filing address certain specific needs that MISO, the Commission and the stakeholder process identified. To ensure that MISO is on the right track to resolving its interconnection backlog, MISO requests that the Commission approve this updated proposal. The proposed new Tariff revisions address the Commissions earlier concerns and will significantly enhance the GIP by reducing queue delays and by improving the precision and timeliness of Interconnection Studies and will enable MISO to take the necessary steps to manage the size of individual cluster studies performed during the interconnection queue process.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Affidavit of Andrew Witmeier

COUNTY OF HAMILTON)

)

STATE OF INDIANA)

Andrew Witmeier, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Andrew Witmeier, and the statements contained therein are true and correct to the best of his knowledge and belief.

Andrew Witmeier

SUBSCRIBED AND SWORN BEFORE ME, this 7th day of November, 2024.

Jennifer L. Miller
Notary Public, State of Indiana
Boone County
Commission Number 697079
My Commission Expires
February 22, 2025

EXHIBIT 1
TO
PREPARED DIRECT TESTIMONY OF
ANDREW WITMEIER

Prepared for:
Midcontinent Independent System Operator
720 City Center Drive
Carmel, IN 46032

MISO Generator Interconnection Queue: M2, M3, and M4 Security Deposits and Return Procedures

Evaluation and Suggested Adjustments

Prepared by:
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Date: September 27, 2023

CONFIDENTIAL MATERIAL

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1. BACKGROUND

The Midcontinent Independent System Operator (MISO) generator interconnection queue has experienced significant growth, leading to a substantial backlog of projects that is negatively impacting MISO stakeholders and interconnection customers. Recognizing this challenge, MISO has undertaken efforts to improve the efficiency of the interconnection queue process and reduce the backlog.

In pursuit of these objectives, MISO has enlisted the expertise of Charles River Associates (CRA) to provide an independent review of current rules for entry to and exit from the interconnection queue. Within the review, we evaluate the security deposits required within the MISO Definitive Planning study process, with a specific focus on the M2, M3, and M4 deposit amounts. The analysis conducted by CRA has relied upon data from the 2017-2022 study cycles, which forms the basis for the charts and recommendations presented in this report.

CRA's historical analysis has concentrated on the volume of interconnection requests, the magnitude of network upgrade costs assessed at different stages of the queue process, and withdrawal rates. These analyses have provided insights into how deposit amounts, policies, and the overall study process can be restructured to enhance the efficiency of the interconnection queue.

2. STATE OF THE QUEUE

A prevailing trend observed with respect to the interconnection queue studies published in recent years[1] is the consistent rise in queue sizes, accompanied by prolonged wait times and elevated withdrawal rates.

2.1. QUEUE SIZE

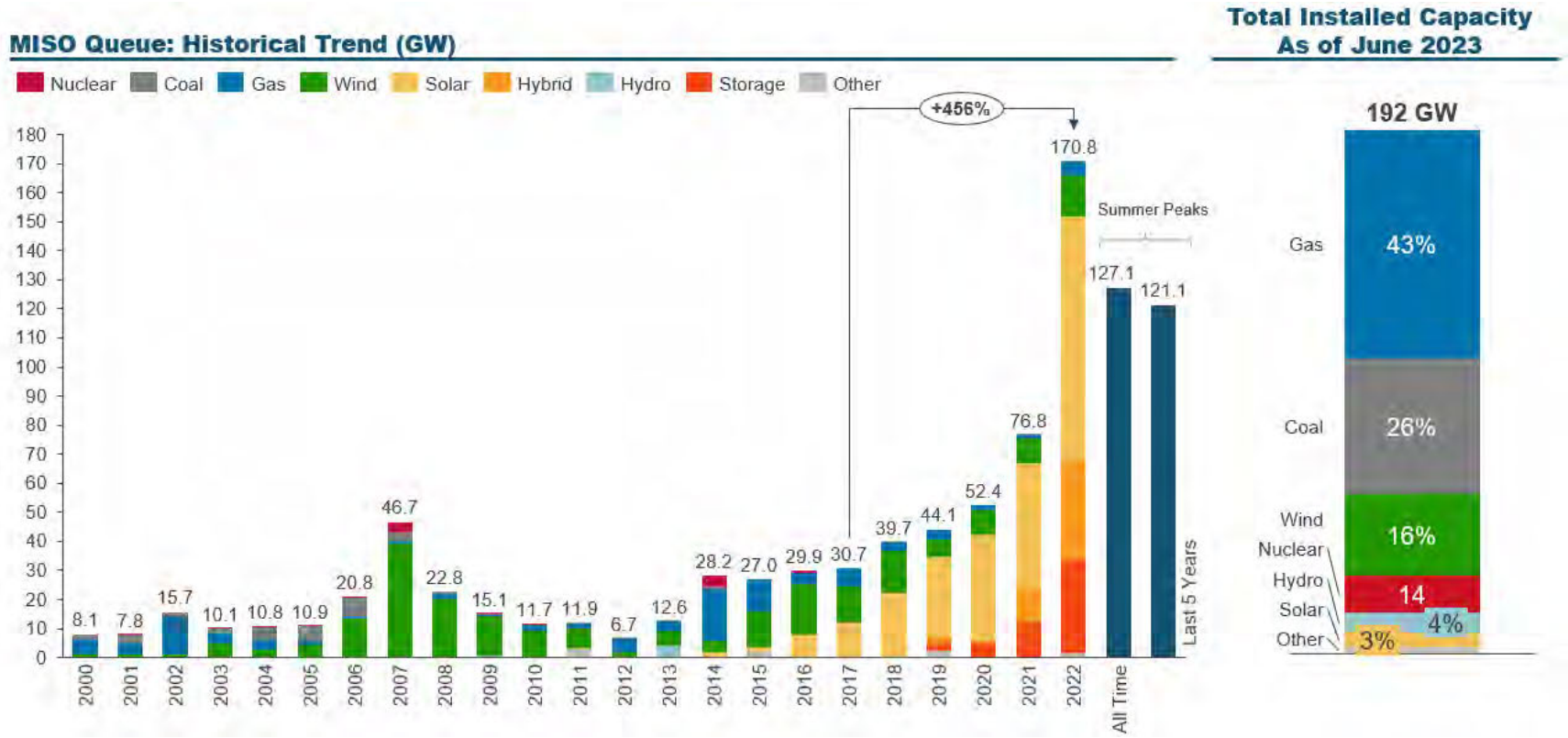
Figure 1 illustrates a concerning trend in the MISO queue. For years, the queue remained relatively stable but has inflated significantly in recent years to increasingly unmanageable levels. Comparing the 2022 queue size to the 2017 cycle, the queue has grown by 4.5 times. Moreover, the 2022 queue size, which stands at 170.8 GW, surpasses the all-time MISO summer peak demand of 127.1 GW and approaches the total MISO installed capacity of 192 GW.

The analysis of the 2022 interconnection queue, as presented in Figure 1, examines the costs associated with bringing all submitted capacity online as installed capacity. Results will likely show that significant costs are required, in the form of network upgrade and affected system costs, to bring all submitted capacity online. This data has been examined to give context to the proposed reforms outlined in this report and to help quantify the suggested magnitudes of deposits required and deposits at risk of forfeiture.

[1] For example, “Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection” published by Berkeley Lab https://emp.lbl.gov/queues

As a practical matter, a significant portion of the queued generation will not ultimately be placed in service and much of the study effort will, arguably, be wasted.

Figure 1. MISO Queue: Historical Trend (GW)



Source: MISO

2.2. QUEUE PHASES, MILESTONES, AND TIMING [2]

The MISO interconnection queue study process is structured into distinct phases and incorporates milestone payments. In the pre-queue phase, interconnection customers (ICs) submit interconnection requests and MISO carries out essential preliminary tasks before commencing a formal study. These tasks include a set of initial screenings and a scoping meeting. A completed application includes an M2 milestone payment of $4,000 per MW studied.

The MISO Definitive Planning Phase (DPP) follows the pre-queue phase. During this phase, detailed studies and planning activities are conducted to assess the feasibility and impact of the proposed project on the MISO transmission system. The DPP consists of three phases: DPP Phase 1 (DPP 1), DPP Phase 2 (DPP 2), and DPP Phase 3 (DPP 3).

In the initial phase of the Definitive Planning Phase (DPP 1), the interconnection customer receives a comprehensive preliminary analysis of their request's impact on the reliability of the transmission system. During this phase, MISO conducts the initial Model Building and Review, followed by the preliminary System Impact Study (SIS). After completing the analysis, interconnection customers reach Decision Point I, where they have two options: (1) withdraw their request and potentially be subject to harm calculations (i.e., calculations to determine whether withdrawal shifted cost from the withdrawn project to other projects), with a potential to lose up to 50% of the M2 deposit, or (2) choose to proceed further in the queue process by paying an additional security deposit (M3). The M3 security deposit equals 10 percent of the network upgrade cost, as assessed in DPP 1, minus the M2 deposit.

DPP 2 is designed to provide the interconnection customer with a revised and more detailed analysis of the interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions resulting from the withdrawal of interconnection requests during DPP 1. Once the revised SIS and affected system analysis are completed, inclusive of estimated upgrade costs, the interconnection customer enters Decision Point 2. Here, if the interconnection customer decides to withdraw, 100% of the M2 deposit becomes at risk (subject to harm calculations), and 100% of M3 is returned. If the project meets penalty-free withdrawal criteria,[3] 100% of the M2 deposit is returned. If the interconnection customer decides to continue in the queue, they are required to submit an M4 deposit. The M4 deposit equals 20% of the network upgrade cost calculated in DPP 2, minus the M3 and M2 deposits.

DPP Phase 3 is designed to provide ICs with a final, detailed analysis of their interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions due to the withdrawals of interconnection requests during Decision Point 2. All milestone deposits (M2, M3, and M4) become at risk and subject to harm calculations upon entry into Phase 3. However, all three deposits may be returned in full upon withdrawal in DPP 3 if the project meets penalty-free withdrawal criteria.

[2] Information in this section is based on MISO's Generation Interconnection Business Practices Manual PM-015-r25

[3] Section 7.6.2.4 Withdrawal and refund due to increase in network upgrade costs of Generator Interconnection Procedures

The Generation Interconnection Agreement (GIA) Execution Phase follows DPP 3. For more detail, see MISO's Generator Interconnection Procedures, and Generation Interconnection Business Practices Manual.

We find that in our sample, the average length of the pre-kick off phase is 305 days and the average length of the DPP1 is 298 days, see Figure 2 below.

Figure 2. Days spent in each queue cycle (2017-2022)

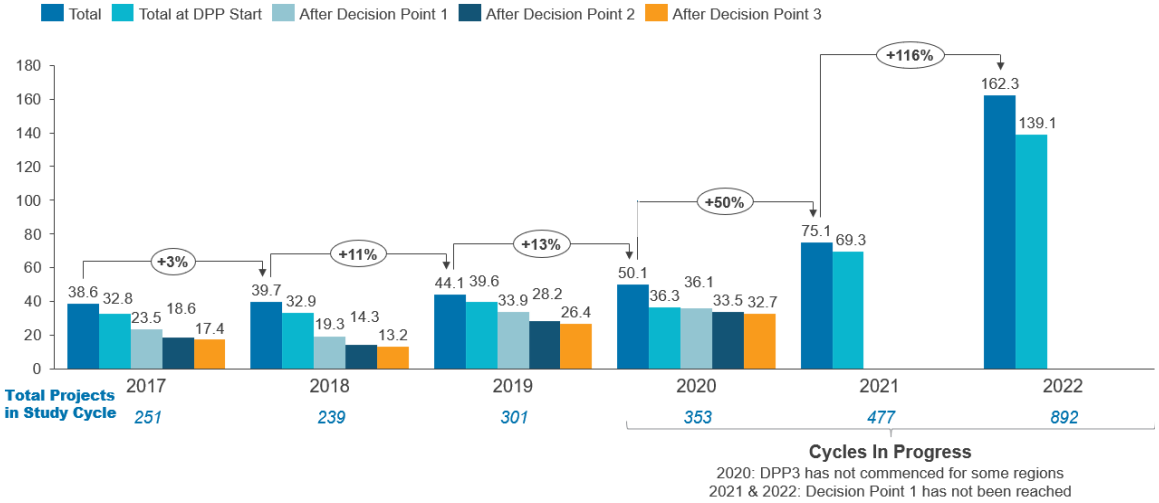
Queue Phase	Average # days in phase
Pre-Kick-Off	305
DPP 1	298
DPP 2	200
DPP 3	187
GIA Execution	142

Source: MISO

2.3. WITHDRAWALS

Figure 3 further illustrates the year-over-year percentage increase in the size of the interconnection queue along with the dynamics of withdrawals. The queue size has experienced significant growth, with the steepest increase occurring between the 2021 and 2022 cycles, where the queue expanded by 116%. The withdrawals are significant and occur at every stage.

Figure 3. MISO Queue Withdrawals by Cycle (GW)



Source: MISO. Note: This figure does not include withdrawals without a specified date.

Table 1. MISO Queue Withdrawals by Cycle, percentages based on MW withdrawn

Status	Withdrawal Phase	DPP-2017-AUG	DPP-2017-FEB	DPP-2018-APR	DPP-2019-Cycle	DPP-2020-Cycle	DPP-2021-Cycle	DPP-2022-Cycle
Active		2%	0%	0%	13%	53%	88%	86%
Done		35%	26%	32%	44%	6%	0%	0%
Withdrawn								
	Pre Kick-off	19%	1%	17%	10%	28%	8%	14%
	Decision Point 1 (DPP 1)	22%	34%	34%	13%	0%	2%	0%
	Decision Point 2 (DPP 2)	11%	17%	13%	13%	5%	0%	0%
	During DPP Phase 3	1%	11%	3%	4%	2%	0%	0%
	During GIA Execution Phase	8%	0%	0%	0%	1%	0%	0%
	Post GIA	2%	11%	1%	0%	0%	0%	0%
	Withdrawn (Other)	0%	0%	0%	2%	6%	2%	0%
Withdrawn Total		63%	74%	68%	43%	41%	12%	14%

Source: MISO.

Table 1 provides an overview of the percentage of total MW in the queue that has been withdrawn at various stages, including Active and Done[4] . Note that as of now, the 2019-2022 queue cycles remain active. Looking at the fully completed cycles in our sample (2017-2018

[4] Done means the project has completed the interconnection queue process.

cycles), nearly 70% of the total generation capacity that entered these cycles was eventually withdrawn. We observe that a considerable percentage of capacity is withdrawn during the Pre-Kick-off phase. The 2022 Cycle for example, which has not yet reached the DPP Phase, has already had 14% of the initially entered capacity withdrawn. This raises concerns about whether some projects are being entered into the queue speculatively without undergoing proper due diligence. Most of the withdrawn projects exit either before the DPP Start or at Decision Point 1, which highlights the need to incentivize more careful project assessment before entry into the queue.

Next, we examine the withdrawal dynamics based on the relative portion of the queue that each participant holds. The company size is determined by considering the total MW of projects within our sample. Table 2 illustrates the overall share of projects and the withdrawal pattern for the top developers in MISO territory.

According to the data in Table 2, the top 3 companies (as defined by requests to enter into the queue) collectively accounted for 30% of the capacity entered into the 2017 - 2022 interconnection queues. Of all applications submitted by these top 3 companies, 72% were eventually withdrawn. As we expand our analysis to include more companies, the overall percentage of withdrawn applications decreases. In comparison, when considering all companies in the sample, the withdrawal rate was 53%. This observation may imply a greater likelihood of speculative entry among the most active companies.

Table 2. MISO Queue Withdrawals by Top Interconnection Customers

	Withdrawn MW 2017 – 2020 Cycles		Point of Withdrawal			
	MW submitted into queue as % of all projects	Out of submitted, % withdrawn	% Withdrawn before DPP Start	% Withdrawn at DPP1	% Withdrawn at DPP2	% Withdrawn Phase 3 and after
Top 3 Companies	30%	72%	32.5%	37.8%	22.6%	5.5%
Top 5 Companies	34%	69%	36.3%	34.8%	21.6%	5.9%
Top 10 Companies	40%	68%	38.4%	32.1%	20.9%	7.4%
Top 15 Companies	43%	67%	37.0%	33.4%	20.2%	6.9%
Top 20 Companies	46%	66%	38.0%	33.2%	19.3%	7.1%
Top 25 Companies	49%	67%	36.4%	32.8%	19.3%	8.6%
All Companies	**100%**	**53%**	**33.6%**	**31.4%**	**19.7%**	**11.0%**

Source: MISO. Note: figures by row may not sum to 100% due to missing withdrawal dates for some projects.

When we consider the timing of withdrawals, the top companies' withdrawal patterns differ from the broader pool of companies in the sample. The top developers are more likely to withdraw in the initial stages of the process and less likely to withdraw in Phase 3 or beyond. This finding suggests that top companies might have greater resources enabling follow-through and

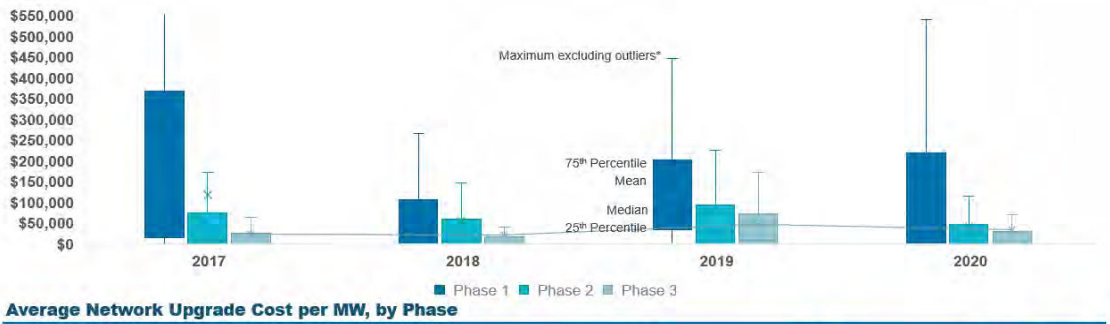
commitment, which explains the lower withdrawal rates at later phases as compared to other companies in the sample.

2.4. NETWORK UPGRADE COSTS

In this section, we analyze the network upgrade costs per MW. As previously discussed in Section 2.2, the network upgrade costs are initially calculated in DPP 1, followed by DPP 2, and ultimately finalized in DPP 3. For a comprehensive overview, Figure 4 illustrates the network upgrade costs for the cycles spanning from 2017 to 2020, allowing for a comparison of average costs across the three DPP phases.

The average network upgrade costs in DPP 1 are notably higher compared to those in DPP 2 and DPP 3. This outcome is not surprising, considering the larger size of the initial queue. As projects progress through the phases, many drop out, leading to a more manageable number of projects being analyzed and, consequently, more realistic network upgrade costs. Additionally, the projects with the highest network upgrade costs are expected to drop out first.

Figure 4. Network Upgrade Cost per MW, by DPP Phase[5]



Average Network Upgrade Cost per MW, by Phase

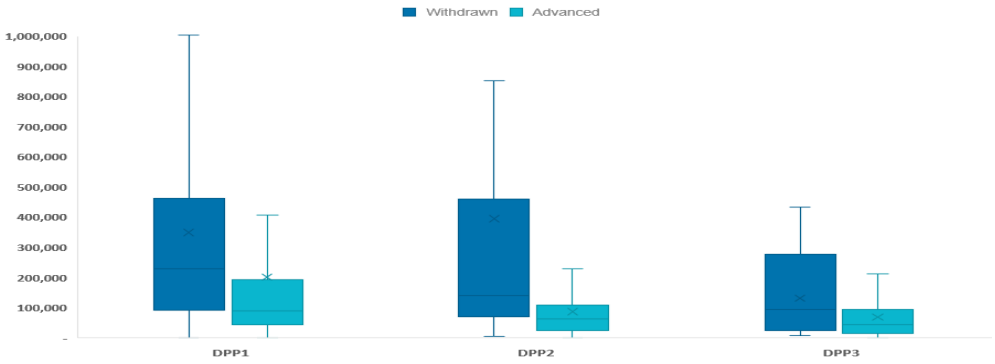
	2017	2018	2019	2020	Average
Phase 1	$341,916	$101,703	$170,781	$297,694	$232,051
Phase 2	$216,525	$100,492	$122,008	$112,098	$138,353
Phase 3	$53,518	$56,483	$82,037	$94,279	$72,514

Source: MISO.

[5] A box plot consists of a rectangular "box" that represents the interquartile range (IQR) of the data, (25th to 75Th percentile), and the "whiskers" show the range of the data. Any data points beyond the whiskers are considered outliers and are not shown on this chart.

We observe that the sample mean (marked as 'x') consistently exceeds the median (denoted by a line). This suggests that most of the projects within each plotted distribution have network upgrade costs lower than the average.

Figure 5. Network Upgrade Cost per MW, by Phase and Status



Average Network Upgrade Cost per MW, by Phase and Status

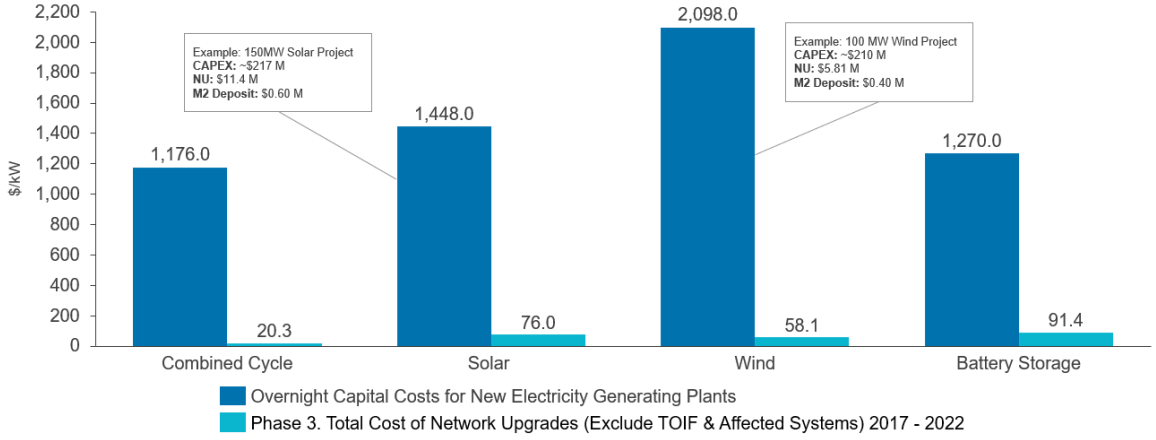
	DPP1	DPP2	DPP3
Withdrawn	$349,601	$395,560	$132,849
Advanced	$201,878	$87,747	$70,059

Source: MISO.

Figure 5 presents the aggregate data for the 2017 – 2020 cycles. It illustrates the distinct cost distributions of network upgrades for projects that either proceeded to the subsequent DPP stage or were withdrawn at each respective DPP stage. At Decision Point 1, the average network upgrade cost per MW for a withdrawn project was $349,601, and projects that advanced to the next stage had an average network upgrade cost of $201,878. As anticipated, the projects that were advanced tend to, on average, have lower costs compared to those that were withdrawn.

The average network upgrade cost for projects that advanced beyond DPP 1 is notably higher than those advanced beyond DPP 2. This suggests that developers have an understanding that the network upgrade costs are likely to decrease in subsequent phases.

Figure 6. Network Upgrade Cost per MW vs. CapEx



Source: MISO (2017-2022 Cycles), EIA AEO (March 2023) Overnight Capital Costs for New Electricity Generating Plants

Figure 6 illustrates the comparison between the capital costs needed to construct a new generation facility and the average network upgrade costs that the same facility is anticipated to incur for securing interconnection in MISO. The network upgrade costs constitute only a fraction of the overall budget that developers are required to allocate.

This consideration plays a role when discussing incentives to deter speculative entry into the interconnection queue. The accepted economic deterrents for unwanted behavior are penalties. To be effective, penalties should be assessed within the context of overall costs and budgets.

3. RECOMMENDATIONS

This section presents our recommendations for MISO queue policies, aiming to achieve the dual goals of reducing the size of the interconnection queue and decreasing the withdrawal rate. Once these challenges are successfully addressed, study times will decrease, leading to enhanced efficiency within the MISO interconnection queue. This improvement will enable MISO to process more projects more quickly than the current situation allows and should result in customers receiving more dependable information with which to make business decisions regarding their projects.

3.1. DEFINITION OF HARM

The interconnection queue within MISO has reached a point where it has become unmanageable at entry, and modeling upgrade costs in the early phases has become unrealistic. Additionally, the frequent dropouts within the interconnection queue create significant uncertainty, making the results of studies unreliable and subject to significant change over the course of the study process. This constant fluctuation requires continual reevaluation, adding complexity to the process. We observed that interconnection requests are withdrawn at every stage, leading to changes in results and even more withdrawals.

Two behavioral aspects behind the problems identified above are (1) speculative entry and (2) frequent withdrawals. The two aspects are intertwined as projects that enter the queue without due diligence regarding readiness and feasibility are more likely to be withdrawn.

Effective preventive measures should be implemented to discourage these harmful behaviors. Creating and enforcing these measures establishes a more responsible environment, minimizing harm. To achieve this, harmful behavior must be clearly defined. Once appropriately defined, it becomes the basis for levying penalties where harmful behavior is proven to exist.

Withdrawals are unlikely to be penalized under the present definition of harm, which is narrowly focused on cost increases to remaining projects due to required Network Upgrades following a project's withdrawal. This definition accounts for situations where shares of required transmission upgrades are allocated to remaining projects after a re-study analysis. However, it may also result in less expensive required transmission upgrades and lower allocated shares, reflecting the stepped nature of upgrade costs as incremental generation capacity is accommodated. Such outcomes do not mean that the remaining projects are unharmed by the withdrawal. On the contrary, they suffer from the additional time required for necessary re-studies and the uncertainty engendered by the constantly changing queue.

Interdependencies among projects and shared information mean that withdrawals inevitably impact other projects through delays and increased uncertainty; these two impacts should be recognized as harmful:

> Delays: The study process is delayed when projects withdraw, and previously identified upgrades may no longer be applicable. This leads to more time required for analysis.
>
> Uncertainty: Projects in the queue rely on network upgrade estimates for crucial business decisions, and these decisions are undermined when projects are withdrawn.

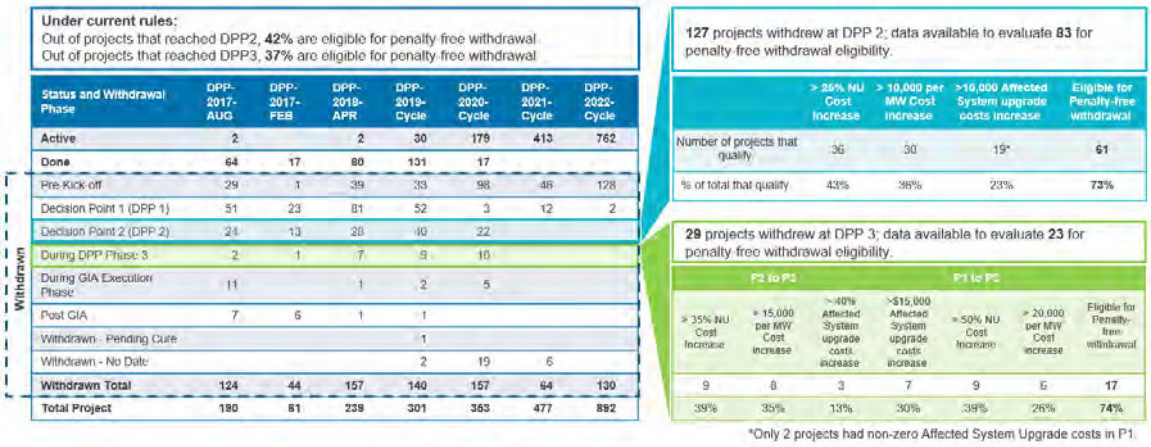
Regardless of why a project is withdrawn from the interconnection queue, such withdrawal invariably inflicts some harm on remaining projects. This harm might be quantifiable in monetary terms but is often intangible and can only be described qualitatively.

Besides the measurable harm of increased upgrade costs, the delays and uncertainty inherent in the process argue for a harm penalty. This penalty, even when the harm isn't directly measurable, should escalate with each stage of the process to encourage early decision-making regarding non-viable projects. The presence of such a penalty recognizes that harm extends beyond mere dollars and cents, encompassing broader impacts on the queue's efficiency and reliability.

3.2. PENALTY FREE WITHDRAWAL ADJUSTMENT

Penalty-free withdrawal should be eligible only for projects facing a significant increase in total costs. Current MISO rules that allow for penalty-free withdrawal are outlined in Section 7.6.2 Refunds of Definitive Planning Phase Milestones (M2, M3, M4) of the Generator Interconnection Procedures (GIP). Figure 7 below summarizes our analysis of the penalty-free withdrawal rules.

Figure 7. Penalty-free withdrawal rules application



Under current rules:
Out of projects that reached DPP2, **42%** are eligible for penalty free withdrawal
Out of projects that reached DPP3, **37%** are eligible for penalty free withdrawal

Status and Withdrawal Phase	DPP-2017-AUG	DPP-2017-FEB	DPP-2018-APR	DPP-2019-Cycle	DPP-2020-Cycle	DPP-2021-Cycle	DPP-2022-Cycle
Active	2		2	30	179	413	762
Done	64	17	80	131	17		
Pre-Kick-off	29	1	39	33	98	46	128
Decision Point 1 (DPP 1)	51	23	81	52	3	12	2
Decision Point 2 (DPP 2)	24	13	28	40	22		
During DPP Phase 3	2	1	7	9	10		
During GIA Execution Phase	11		1	2	5		
Post GIA	7	6	1	1			
Withdrawn - Pending Cure				1			
Withdrawn - No Date				2	19	6	
Withdrawn Total	124	44	157	140	157	64	130
Total Project	190	61	239	301	353	477	892

127 projects withdrew at DPP 2; data available to evaluate **83** for penalty-free withdrawal eligibility.

	> 35% NU Cost increase	> 10,000 per MW Cost increase	>10,000 Affected System upgrade costs increase	Eligible for Penalty-free withdrawal
Number of projects that qualify	36	30	19*	61
% of total that qualify	43%	36%	23%	73%

29 projects withdrew at DPP 3; data available to evaluate **23** for penalty-free withdrawal eligibility.

P2 to P3				P1 to P2		
> 35% NU Cost increase	> 15,000 per MW Cost increase	> 40% Affected System upgrade costs increase	>$15,000 Affected System upgrade costs increase	> 50% NU Cost increase	> 20,000 per MW Cost increase	Eligible for Penalty-free withdrawal
9	8	3	7	9	6	17
39%	35%	13%	30%	39%	26%	74%

*Only 2 projects had non-zero Affected System Upgrade costs in P1.

Source: MISO

The penalty-free withdrawal procedure is based on a comparison between the previously estimated network upgrade cost within the same cycle and the new estimates. As such, this procedure is only applicable at Decision Point 2 and when the DPP3 cost estimates become available.

Current rules allow for a broad set of circumstances to qualify. For example, projects that experience a significant decrease in network upgrade costs may still qualify if affected systems costs increase. This is one of the key reasons why penalty-free withdrawals apply to a large number of projects in the queue. For example, 42% of all projects that reached DPP2 are eligible for penalty-free withdrawal, and 37% of all projects that received network upgrade costs in phase 3 are eligible for penalty-free withdrawal in that phase.

Simple and efficient rules ensure that only projects facing significant increases in overall costs qualify for penalty-free withdrawal. We suggest streamlining the rules and applying only a percentage increase in combined network upgrade and affected systems costs from DPP1 to DPP2 or DPP2 to DPP3. That is, streamline rules to allow penalty-free withdrawal if:

Combined NU + AS cost increased by 50% from P1 and P2 (1)

Combined NU + AS cost increased by 35% from P2 and P3 (2)

The suggested thresholds of 50% and 35% are selected using data in Table 3 below. First column in Table 3 is the threshold, second shows the % of projects that reached DPP2 that would be eligible for penalty free withdrawal under (1) above, and the third column shows the % of projects that reached DPP3 eligible for withdrawal penalty-free withdrawal under (2) above.

At the suggested threshold of 50% cost increase from P1 to P2, 30% of all projects that reached DPP2 would be eligible for penalty-free withdrawal. At the suggested threshold of 35% cost increase from P2 to P3, 20% of all projects that reached DPP3 would be eligible for penalty-free withdrawal.

Table 3. Sensitivity of Withdrawal Eligibility to NU + AS Threshold

Combined NU + AS % Increase Threshold	P2 to P1: % of Projects that Reached DPP2 Eligible for Withdrawal	P3 to P2: % of Projects that Reached DPP3 Eligible for Withdrawal
10%	43%	27%
20%	37%	22%
25%	36%	21%
30%	**34%**	20%
35%	33%	20%
40%	31%	**18%**
45%	31%	16%
50%	30%	15%
55%	29%	14%
60%	29%	13%
65%	27%	13%

Source: MISO

3.3. M2, M3 AND M4 ADJUSTMENTS

We recommend that MISO adjusts M2, M3, and M4 deposits to better reflect potential harm caused by a withdrawal at each study phase.

In The M2 deposit should be more representative of the final NU payment and significant enough to discourage speculative behavior. To aid our analysis of the appropriate deposit we consider average per MW costs in each phase of DPP cycle. We consider a range of 15% to 25% of the average NU cost in Phase 3 to determine a reasonable value range for the M2 deposit amount.

Table 4. Network Upgrade Costs[6]

Study Cycle	Average of NU Cost per MW, Phase 1	Average of NU Cost per MW, Phase 2	Average of NU Cost per MW, Phase 3	15% of NU Cost in Phase 3	20% of the NU Cost in Phase 3	25% of NU Cost in Phase 3
DPP-2017-AUG	$177,999	$118,107	$53,583	$8,038	$10,717	$13,396
DPP-2017-FEB	$840,358	$521,006	$53,247	$7,987	$10,649	$13,312
DPP-2018-APR	$101,703	$100,492	$56,483	$8,472	$11,297	$14,121
DPP-2019-Cycle	$170,781	$122,008	$82,037	$12,306	$16,407	$20,509
DPP-2020-Cycle	$297,694	$112,098	$94,279	$14,142	$18,856	$23,570
Total In-Sample Average	**$232,051**	**$138,353**	**$72,514**	**$10,877**	**$14,503**	**$18,129**
Total in-Sample Median	**$80,624**	**$70,690**	**$48,420**	**$7,263**	**$9,684**	**$12,105**

Source: MISO

We recommend an increase of the M2 amount from $4,000 / MW to a value in the range of $10,000 to $14,000 / MW.

Deposits should increase at each stage, reflecting harm that occurs with withdrawal at later stages in the study process. Additionally, we suggest that M3 and M4 deposits should never be negative. Negative or zero deposits are not representative of harm that occurs should a project withdraw. We suggest adjusting M3 and M4 formulas to:

$$M3 = \text{Max of } \$1{,}000 \text{ and } ((10\% * NU) - M2)$$

$$M4 = \text{Max of } \$1{,}000 \text{ and } ((20\% * NU) - M3 - M2)$$

We believe that this deposit structure more accurately aligns with the network upgrade costs that developers are likely to incur.

3.4. Fixed Penalty Schedule

To mitigate the issues of an unwieldy queue size and frequent withdrawals, it is essential to implement penalties for detrimental practices. As previously discussed, both entering the queue without adequate due diligence and exiting the queue by interconnection customers contribute to an unmanageable queue size and create significant uncertainty.

Penalties are a proven economic lever for curbing undesirable behavior. For such penalties to be effective, they must be both substantial and consistently applied when unwanted actions occur.

Requiring a deposit alone is not a sufficient deterrent unless it is integrated with a comprehensive penalty structure. We propose implementing a fixed penalty schedule in conjunction with the current penalties to address this. Specifically, the current total amounts at risk from the DPP1 and beyond will remain unchanged. However, a predetermined percentage of the M2 deposit will be forfeited at withdrawal, regardless of the specific harm calculations. This percentage should

[6] Similar table based on median values is included in the Appendix

escalate with each successive phase of the DPP. We recommend that this penalty be applied to every withdrawal, extending even to those that occur before the commencement of the DPP.

Table 5 illustrates the suggested penalty schedule with an example.

Table 5. Current and Potential Penalties by DPP Cycle

Withdrawal Time/ Stage of the Cycle	Current Penalties: at risk subject to harm calculations	Suggested Penalty Schedule: Example		
		Fixed Penalty Schedule	*Harm Calculation*	*Penalty-Free withdrawal*
Before DPP Start	No penalty	10% of M2 Deposit	Doesn't apply	Doesn't apply
Decision Point 1	50% of M2 at risk	25% of M2 Deposit	Applies	Doesn't apply
Decision Point 2	100% of M2 at risk	50% of M2 Deposit	Applies	Applies
During Phase 3	M2, M3, and M4 at risk	75% of M2 Deposit	Applies	Applies
GIA Execution Phase and beyond	M2, M3, and M4 at risk	100% of M2 Deposit	Applies	Doesn't apply

Source: MISO

We suggest distributing the collected penalties pro-rata to completed projects of the same cycle. This provides additional support for projects that go through the process and additional incentive for interconnection customers to complete projects.

3.5. QUEUE CAP PER CYCLE

Robust demand for generation interconnection has caused the MISO queue to grow to an unmanageable size, with interconnection requests exceeding what MISO can process in a single cycle, contributing to a substantial backlog.

To mitigate the negative impact of excessive requests on participants and the overall study process, establishing a queue cap might be a solution. The implementation of a queue cap not only limits these detrimental effects but also strengthens the case for withdrawal penalties at every stage, including pre-kick-off.

The excessive interconnection requests compromise other study cycle participants and the overall integrity of the study process. As previously shown, these excessive requests can artificially inflate the magnitude of network upgrade costs in the early stages of the study cycle, leading to escalating financial and manpower burdens on MISO and other stakeholders as the queue size surpasses reasonable limits. Moreover, dissatisfaction with the process could fuel more speculative requests, and projects forced to drop out may swell the number of requests seen in subsequent study cycles.

MISO should determine the level of the queue cap along with its application across study regions, cycles, and possibly entities. The cap should be designed considering certain criteria for MISO overall and by region. For example, the following could be considered:

- Peak load and forecasted peak load.
- Installed capacity, guaranteed additions, and expected retirements.
- Reliability and resource adequacy.

All applications in excess of the cycle queue cap should be entered into the next cycle.

To give a tangible example, the queue cap per cycle could be set as a percentage of the forecasted peak load and/or installed capacity.

3.6. PER DEVELOPER CAP

Implementing a per-developer cap can be an approach to ensuring fairness within the interconnection queue, though it may present challenges in execution. To prevent a single developer from having disproportionate control or excessively entering multiple projects, it is advisable to consider specific safeguards when putting an overall queue cap in place.

These safeguards should be designed to maintain a balanced playing field among developers. It's important to recognize that no specific threshold is universally accepted to spark antitrust concerns; rather, this depends on a variety of factors, including market concentration, the potential for market manipulation, barriers to entry, and the possibility of harm to competition.

If an overall queue cap is put in place, we recommend considering a per-developer cap as well, set at a level between 5% and 15% of the overall queue cap per cycle. The implementation of a per-developer cap would necessitate a robust administrative process, with certain key elements to be included. These could encompass:

- **Authentication**: Define the entity or organization that is subject to the cap. Clear procedures should be established to ensure that all branches or subsidiaries of the same organization are included under the same cap.
- **Monitoring and Reporting**: Establish a system to track the project entries of each developer.
- **Verification**: Develop processes to validate the reported information provided by developers.
- **Transfers**: Ensure that transfers do not result in cap violations.
- **Penalties**: Define penalties for developers who exceed the prescribed limits.
- **Appeals and Dispute Resolution**: Establish a process for developers to appeal decisions related to cap enforcement.
- **Regular Review and Adjustment**: Conduct regular reviews of the cap's effectiveness and consider adjustments if necessary.

4. SUMMARY

CRA’s analysis supports the argument that reform to generator interconnection queue rules for queue entry and exit could alleviate interconnection constraints. A key step to reform is an

adjustment to the definition of harm. The new definition should acknowledge that withdrawn projects harm those remaining in the queue beyond cost shifting via queue delay and uncertainty. One suggestion to reducing queue sizes is that MISO establish queue cap rules. These caps, either in the form of regional caps or developer caps per cycle, could limit excessive requests detrimental to other participants and the overall study process. Updating the monetary value placed on entering, remaining in, and withdrawing from the queue will prevent speculative projects from entering the interconnection process. CRA recommends increasing the M2 deposit to a value in the range of $10,000-$14,000/MW and adjusting the M3 and M4 deposit formulas to a minimum of $1,000 to reflect final costs better. CRA also recommends that MISO implement an escalating fixed penalty schedule, including a minimum pre-kick-off stage withdrawal penalty to support the queue cap implementation. The penalty-free withdrawal rules should be updated to consider the overall percentage increase in combined network upgrades and affected system costs. Penalty-free rules should not apply after phase 3.

5. APPENDIX

The table presented below is a revised version of Table 4 from the report, adjusted to reflect median values. We've incorporated this table in response to feedback from stakeholders.

The values in this table support our recommendation for the M2 deposit, particularly when greater emphasis is placed on values from the latest cycles. Giving more weight to values from recent studies offers a more accurate representation of the queue's current status.

Table 6. Network Upgrade Costs, Median Values

Study Cycle	Median of NU Cost per MW, Phase 1	Median of NU Cost per MW, Phase 2	Median of NU Cost per MW, Phase 3	15% of Median NU Cost in Phase 3	20% of Median NU Cost in Phase 3	25% of Median NU Cost in Phase 3
DPP-2017-AUG	$ 89,051	$ 52,000	$ 42,948	$ 6,442	$ 8,590	$ 10,737
DPP-2017-FEB	$ 655,871	$ 111,467	$ 35,815	$ 5,372	$ 7,163	$ 8,954
DPP-2018-APR	$ 67,918	$ 55,860	$ 36,524	$ 5,479	$ 7,305	$ 9,131
DPP-2019-Cycle	**$ 100,511**	**$ 75,228**	**$ 56,814**	**$ 8,522**	**$ 11,363**	**$ 14,203**
DPP-2020-Cycle	**$ 135,621**	**$ 80,175**	**$ 65,872**	**$ 9,881**	**$ 13,174**	**$ 16,468**
Total in-Sample Median	$ 80,624	$ 70,690	$ 48,420	$ 7,263	$ 9,684	$ 12,105

Source: MISO

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 113
Inst. Pol'y Integrity Report



Enough Energy

A Review of DOE's Resource Adequacy Methodology

Jennifer Danis
Christoph Graf, Ph.D.
Matthew Lifson

July 2025

Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

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The authors thank Dr. Adria Brooks and Rob Gramlich for their valuable feedback.

This report does not purport to present the views, if any, of NYU School of Law.

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Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1*: *Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

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1 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

2 U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.

- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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11 *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

12 *Id.* at 39, 41.

13 Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

14 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

15 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

The Multi-Metric Approach

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

Accounting for Tail Risks

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5th percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95th percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.,* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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97 An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

98 Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

99 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

100 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

101 Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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102 *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

103 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

104 *Id.*

105 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

106 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

107 Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

108 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

109 *Id.* at 37–38.

110 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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[118] Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

[119] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

[120] *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

[121] Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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123 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

124 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

125 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

126 *Id.* at 8.

127 *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

128 *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

129 *See generally* Adria E. Brooks et al., *supra* note 90.

Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

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145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

Additions

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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152 *Id.* at 105 tbl.8.4

153 *Id.*

154 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

155 *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

156 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030**.") (bolded text in original).

157 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

158 *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

Retirements

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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169 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

170 *Id.* at 12.

171 *Id.*

172 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

173 Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

174 Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

175 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

176 *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

Load

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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177 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

178 Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

179 S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

180 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

181 Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

182 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

Interregional Imports

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

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183 *See id.* at 9, 17.

184 *Id.* at 18, 12, A-1 (emphasis added).

185 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.

186 *Id.* at 17–24.

187 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

188 *Id.* at 15522.

189 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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190 *Id.* at 20–42.
191 Id. at 5.
192 *Id.* at 27, 30, 32, 40.
193 *Id.* at 19.

Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[209]

(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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210 Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

211 *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

212 Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

213 Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

214 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

215 *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

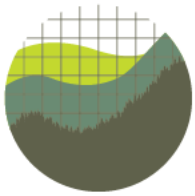
216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.



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