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 NONLABOR O&M EXPENSES ASSOCIATED WITH COALFIRED 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 POSTRETIREMENT 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**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

REDACTED PUBLIC'S EXHIBIT NO. 10

TESTIMONY OF OUCC WITNESS PETER M BOERGER, PHD

JANUARY 20, 2023

Respectfully submitted,

____

Kelly Earls, Attorney No. 29653-49
Deputy Consumer Counselor
OFFICE OF UTILITY CONSUMER COUNSELOR
115 W. Washington St. Suite 1500 South
Indianapolis, IN 46204
Email: KeEarls@oucc.in.gov
infomgt@oucc.in.gov

**VERIFIED DIRECT TESTIMONY OF PETER M. BOERGER, PH.D.
ON BEHALF OF
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
NORTHERN INDIANA PUBLIC SERVICE COMPANY
CAUSE NO. 45772**

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Peter M. Boerger. My business address is 305 W 46th Street, Indianapolis, IN 46208.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am President of Economics Workshop, LLC, a consulting firm I founded in 2022.

Q: WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A: Prior to founding my consulting firm, I worked on the staff of the Indiana Office of Utility Consumer Counselor ("OUCC") as a senior analyst, Assistant Director of the Electric Division and Director of the Electric Division at various times over two stints with the Agency—1997 to 2005 and 2015 to 2022. There I worked on and/or presented testimony to the Indiana Utility Regulatory Commission ("IURC" or "Commission") in a wide range of matters, covering such topics as potential restructuring of Indiana's electric system, the creation of what was then known as the Midwest Independent System Operator, the emergence of merchant power plants in Indiana, base rate cases, holding company mergers, Certificates of Public Convenience and Necessity and a wide assortment of miscellaneous electric utility matters. In addition to my experience in utility regulation I have worked as a public policy analyst at Indiana's Legislative Services Agency and in entities pertaining to economic development policy and environmental policy. Before attending graduate school, I began my career working as a mechanical engineer. I hold a Ph.D. in Engineering Economics from the School of Industrial Engineering at Purdue University, West Lafayette, a Master of Science degree in Technology and Public Policy from the Center for Public Policy and Public Administration at Purdue, and a Bachelor's Degree in Mechanical Engineering from the University of Wisconsin – Madison.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to review the implementation of Norther Indiana Public Service Company's ("NIPSCO") rate Industrial Power Service Large - Rate 831, as approved in Cause No. 45159, and NIPSCO's proposal for its modification and continuation in this Cause as Rate 531.

Q: HOW DID YOU PREPARE FOR PRESENTING YOUR TESTIMONY IN THIS CAUSE?

A: I reviewed relevant portions of the Commission's order in Cause No. 45159 establishing Rate 831 and portions of orders in prior NIPSCO rate cases pertaining to service of NIPSCO's large industrial customers. I reviewed relevant portions of NIPSCO testimony and workpapers in this Cause, including portions of the class cost of service study ("CCOSS") establishing class revenue allocations. I questioned NIPSCO through discovery regarding its implementation of Rate 831 and reviewed its discovery responses. Additionally, I reviewed a number of decisions from the Federal Energy Regulatory Commission ("FERC"), documents published by the Mid-Continent Independent System Operator ("MISO"), and industry literature.

Q: HOW IS YOUR TESTIMONY ORGANIZED?

A: First, I provide a history and overview of Rate 831 and what NIPSCO is seeking in this Cause related to that rate. Following that I discuss the combined effect of Rate 831 and a change to 4CP production cost allocation in NIPSCO's last base rate case and the further effects on other rate classes if NIPSCO's largest customers continue to reduce the amount of firm service they take from NIPSCO. I then identify a significant difference between allocation determinants relevant to Rate 831 customers for purposes of cost allocation in this proceeding versus the amount identified in NIPSCO's dealings with the MISO and propose an approach to stabilizing the level of firm load for which these customers are responsible. Next, I review potential reliability-related effects of the Rate 831 approach to serving these large customers and propose action that the Commission can take to minimize the potential for such negative consequences. Following that discussion, I consider what the future holds for NIPSCO's service of these large industrial customers.

Q: TO THE EXTENT YOU DO NOT ADDRESS A SPECIFIC ITEM IN YOUR TESTIMONY, SHOULD IT BE CONSTRUED TO MEAN YOU AGREE WITH NIPSCO'S PROPOSAL?

A: No. My silence regarding any topics, issues, or items NIPSCO proposes does not indicate my approval of those matters. Rather, the scope of my testimony is limited to the specific items addressed herein.

II. RATE 831

Q: WHAT IS RATE 831?

A: Rate 831 is a rate that allows some of NIPSCO's largest industrial customers to obtain a portion of their power at rates established by the MISO energy market, rather than at rates reflecting NIPSCO's embedded costs. In exchange for the ability to avoid paying rates funding NIPSCO's generation-related revenue requirement for a significant portion of NIPSCO's load, Rate 831 customers sign contracts obligating them to a level of firm purchases (called "Tier 1" purchases) for a period of time.

Q: WHAT WAS THE MOTIVATION FOR RATE 831?

A: Industrial ratepayers have argued for years regarding the difficulty to stay competitive paying NIPSCO's electric rates, with the implication they should be provided relief and that they might otherwise need to build more self-generation or leave NIPSCO's system. NIPSCO was concerned[1] if these large industrial ratepayers were to exit NIPSCO's system after building new capacity to serve them it would leave the utility with large amounts of unused generating capacity, with those costs passed on to other ratepayers. Thus, the largest industrial ratepayers and NIPSCO proposed Rate 831 in Cause No. 45159 to address the situation.

Q: HOW DID RATE 831 ADDRESS THAT SITUATION?

A: It allowed these customers to avoid paying for NIPSCO's production costs for a large share of their load, which addressed their cost concerns. It addressed NIPSCO's concerns by requiring these customers to contract for a set amount of capacity—eliminating the NIPSCO's need to plan for serving a large share of the load of these customers and the related potential for losing large increments of load after such plans were implemented.

Q: DO THESE CUSTOMERS HAVE TO OBTAIN ELECTRICITY ELSEWHERE IN PLACE OF POWER THEY WERE PREVIOUSLY OBTAINING FROM NIPSCO'S GENERATING UNITS?

A: Yes. They obtain the power from[2] wholesale markets instead of from NIPSCO resources. Those purchases have a cost and, thus, theoretically might lead to overall costs as much or more than what NIPSCO was charging. But, based upon my experience viewing MISO markets at that time, the prices these customers saw for obtaining power from MISO's markets were attractive compared to what NIPSCO was charging, which is, in my estimation, why they were agreeable to this arrangement.

Q: WHY HAVE THE WHOLESALE POWER PRICES SOUGHT BY RATE 831 CUSTOMERS BEEN ATTRACTIVE COMPARED TO NIPSCO'S REGULATED RATES?

A: In part, lower MISO market prices have been the result of underlying market forces. For one thing, natural gas prices, which largely drive wholesale electricity prices, have until recently been at historic lows. Additionally, MISO capacity market prices have, with few exceptions, been near

[1] NIPSCO witness Erin Whitehead in this Cause explains the motivation behind the request for the Rate 831 in Cause No.45159 on p,35, ll.3-9 of her direct testimony, Petitioner's Exhibit No. 2.

[2] Rate 831 customers do not purchase the power directly from the MISO markets for their Tier 2 and Tier 3 service. NIPSCO as the "Market Participant" purchases the energy or capacity on their behalf and invoices them.

zero for many years. "Nearly free" looks quite attractive compared to rates that are required to fund the very real cost of building capacity to serve customers reliably and resiliently over a 20- or 30-year time horizon. Large industrial customers in competitive industries will, of course, seek to take advantage of such temporary market prices—dips which regulated prices cannot follow as closely as can wholesale markets. I will call those reasons for low wholesale prices "economic" reasons. There are also reasons grounded in the nature of utility regulation, what I will call "regulatory" reasons for cost differences.

One major difference between the factors underlying regulated prices compared to market prices is the need to keep public utilities in business, even if they make (what are later determined to be) unwise investment decisions, due to the need for maintaining reliable and resilient service. The free market, in contrast, enforces a brutal justice on companies that make bad decisions. Another "regulatory" reason for regulated prices being higher than wholesale prices is the difficulty of eliminating operational inefficiency at regulated utilities. While commissions and consumer representatives such as the OUCC work hard to eliminate such inefficiencies from regulated rates, it is often difficult to differentiate between a necessary and an unnecessarily high cost.

While that difficulty and ongoing challenge is likely unavoidable in total, there are benefits[3] to maintaining a system of regulated retail utilities, such as providing for greater control over the provision of reliable utility service. But between the "economic" and "regulatory" reasons for wholesale rate attractiveness, Rate 831 customers reached an agreement with NIPSCO in Cause No. 45159 to access low wholesale prices and avoid embedded utility costs that wholesale markets would not require them to fund over a large share of their load.

Q: WHO PAYS FOR NIPSCO'S COSTS THAT ARE BEING AVOIDED BY RATE 831 CUSTOMERS?

A: All remaining customers, which includes other industrial customers not in Rate 831, commercial customers and residential customers. All remaining NIPSCO customers have the added burden of covering the costs which made NIPSCO's rates unattractive to Rate 831 customers, making the rates of these remaining customers even more unattractive.

---

[3] A recent study by MIT researchers reviewing the effects of generation deregulation found that the cost of producing electricity did in fact go down compared to regulated states, which by itself would provide hope for such a scenario. Unfortunately, they also found that prices to customers did not decline along with the reduction in costs, which they surmise was due to the exercise of market power in these deregulated markets. The deregulation of the generation side of electricity provision has not been the panacea that was expected. The workpaper resulting from the study can be found at https://climate mit.edu/posts/deregulation-market-power-and-prices-evidence-electricity-sector.

Q: ARE YOU SAYING THERE WERE NOT ANY LEGITIMATE COUNTERBALANCING REASONS IN FAVOR OF APPROVING THE SETTLEMENT IN CAUSE NO. 45159 WHICH CREATED RATE 831?

A: No. The threat to build more self-generation facilities or to shift production made this a difficult decision. And as I communicated in that Cause, the OUCC recognizes the importance of these large customers to the economy of northwest Indiana. My testimony in this Cause is not intended to rehash the last case but to take a detailed look at the rate, how to think about it, how it has performed in its initial years and where we are going with it, and NIPSCO's service to these customers in the long run.

III. THE EFFECT OF RATE 831 ON COST ALLOCATIONS

Q: HOW DID APPROVAL OF THE SETTLEMENT CREATING RATE 831 IN CAUSE NO. 45159 AFFECT COST ALLOCATION METHODOLOGY USED TO ALLOCATE COSTS TO THE RATE CLASSES?

A: Approval of that settlement made two significant changes that affect cost allocations to other rate classes. First, as discussed above, it removed from a significant portion of industrial load the responsibility of supporting NIPSCO's embedded production costs. Second, it granted approval of a 4CP methodology that had never been approved for NIPSCO previously.

Q: CAN YOU QUANTIFY THE MAGNITUDE OF THAT CHANGE IN ALLOCATION FACTORS RESULTING FROM THE COMMISSION'S ORDER IN CAUSE NO. 45159?

A: Yes. I will use the residential rate class to illustrate. Using the data provided in NIPSCO witness John D. Taylor's workpaper "NIPSCO Electric External Allocators_WORKPAPERS.xlsx," and using a 12CP methodology without the effects of the Rate 831 design approved in Cause No. 45159, would result in production cost allocation to the residential class of 31.02%.[4] The proposed allocation to the residential class (which includes the 4CP allocation and the new residential rate class) is 47.14%. This represents a 16.12% increase in allocated share, which is a 52% increase[5] in the residential share of production costs above what would be the case had both 4CP and Rate 831 provisions not been approved.

---

[4] Which is equivalent to the "Transmission" allocation factor in the "External Allocators" tab of this workpaper.
[5] Calculated as (47.14/31.02 – 1). In other words, for every $1 in cost responsibility under a 12 CP allocation methodology and without approved Rate 831 Tiers 2 and 3 structure, customers pay $1.52 with those approvals from Cause No. 45159.

Q: CAN YOU QUANTIFY HOW MUCH OF THAT INCREASED COST RESPONSIBILITY IS DUE TO A 4CP VS. 12 CP ALLOCATION AND HOW MUCH TO THE RATE 831 STRUCTURE?

A: Yes. My calculations show that the change to implement the provisions of Rate 831 as approved in Cause No. 45159 increases residential customers' share of production costs in the current Cause by 7.47%, whereas the change from a 12CP to a 4CP allocation increases the residential class share of production costs in this Cause by 8.66%, more than doubling the effect of the Rate 831 changes. For reference, I calculate the decrease in the allocation factor for the Rate 831 rate class due to Rate 831 effects to be 17.58% vs. a 1.9% decrease due to a shift from 12CP to 4CP.

Q: DOES NIPSCO HAVE A LONG HISTORY OF RATES BASED UPON 12CP ALLOCATIONS?

A: Yes. In Cause No. 43546, the most recent NIPSCO base rate case prior to Cause No. 45159 in which cost allocation was not the result of a settlement, approved on August 25, 2010, the Commission refers[6] to the most recent approved cost allocation methodology prior to that date being a 12CP methodology approved in Cause No. 37023, which had a final order issued in the 1980s.

Q: DO YOU HAVE A RECOMMENDATION BASED ON THE RESULTS YOU HAVE JUST PRESENTED?

A: Yes. I ask the Commission to consider the two major changes approved in the last rate case, each of which by itself, as I have shown, causes a significant change in cost allocation. The approval of a 4CP methodology in Cause No. 45159 also represented a significant departure from the Commission's history of approving 12CP cost allocation methodologies in cases where cost allocation was adjudicated. Under the OUCC proposal for an across-the-board rate increase, as presented in the testimony of OUCC witness Glenn Watkins, changes to production cost allocation factors will have no effect on rates coming out of this Cause; however, they would have an effect on any current or new trackers which make use of production cost allocation factors between now and when rates are changed in NIPSCO's next base rate case. On the basis of the decision factors presented here, and in the context of the Commission's longstanding approach to approving cost allocation methodologies, it would be reasonable and prudent for the Commission to return to a 12CP allocation for production-related costs recovered through trackers between the date that rates are implemented in this Cause and the date when rates are changed in NIPSCO's next base rate case.

---

[6] Page 85 of the Final Order in Cause No. 43526.

IV. THE IMPORTANCE OF MAINTAINING FIRM LOAD

Q: HOW MUCH FIRM LOAD DID RATE 831 CUSTOMERS CONTRACT FOR IN CAUSE NO. 45159 AND HOW MUCH ARE THEY COMMITTED TO TAKE UNDER THE SETTLEMENT PROPOSED FOR APPROVAL IN THIS CAUSE?

A: Rate 831 customers, coming out of NIPSCO's base rate case in Cause No. 45159, signed contracts to take 176 MW of firm capacity and agreed to cover production demand costs covering 194 MW of firm load. In the settlement proposed for approval in this Cause, Rate 531 customers are proposed to take an actual firm capacity of 170MW and cover 180 MW of firm load costs. [7]

Q: DO THOSE LEVELS OF FIRM LOAD STILL REPRESENT AN IMPORTANT PART OF COVERING NIPSCO'S PRODUCTION COSTS?

A: Yes. While those levels represent nowhere near the levels of production cost allocation prior to the creation of Rate 831, this rate class still represents an important share of NIPSCO's firm load.

Q: IS IT IMPORTANT TO MAINTAIN THIS SMALLER BUT STILL SIGNIFICANT SHARE OF COST COVERAGE FOR NIPSCO'S PRODUCTION COSTS GOING FORWARD?

A: Yes. There are indications[8] that these customers will seek to continue decreasing their load at future opportunities. It is important in this rate to set the stage to minimize losses in production cost coverage resulting from these customers.

Q: WHAT REASONABLE MODIFICATIONS COULD BE MADE TO NIPSCO'S PROPOSED ARP TO REDUCE OR ELIMINATE FIRM LOAD LOSS IN THE FUTURE?

A: One idea would be to institute a transition charge for additional reductions to Tier 1 load, as the OUCC proposed in Cause No. 45159, which would impose a cost on customers, calculated to cover NIPSCO's legacy assets for that share of NIPSCO's firm load. The Commission did not agree with a transition charge in Cause No. 45159, but I raise the idea again as the OUCC continues to be concerned about the impact of these industrial customers leaving the system on remaining captive customers. A transition charge has been used successfully implemented in many states to deal with stranded generation costs, either from industry restructuring, or large customers leaving a utility's system. For example, the OUCC has recently identified a law and related rules in Nevada that provide additional support for the concept of compensating other customers when load voluntarily leaves a system.[9]

---

[7] See NIPSCO witness Whitehead testimony p.39, ll.12-17.
[8] See Whitehead p. 38, ll. 10-14.
[9] Chapter 704B of the Nevada Revised Statutes ("NRS") and Chapter 704B of the Nevada Administrative Code ("NAC").

As an alternative to a transition charge another option would be to raise the minimum size for participation in this rate class, which would create a higher "floor" for participating — I propose raising the floor to 30 MW instead of the current 10 MW requirement. This would set a floor for total firm service higher than established under the current rate structure. Based upon my review of confidential customer documents, <<CONFIDENTIAL [redacted] CONFIDENTIAL>> For this reason, it would be important to modify NIPSCO's tariff to ensure that other industrial rates to which these customers might need to migrate would have a minimum size restriction no higher than 10 MW.

Q: WOULD A MOVE TO INCREASE THE MINIMUM SIZE RESTRICTION INCREASE THE RISK OF HAVING THESE CUSTOMERS BUILD SELF-GENERATION OR CLOSE THEIR FACILITIES?

A: Not materially, in my estimation. I expect that, while there might be some small level of such increase in risk, the increase in minimum firm load that would be required of these companies under a 30 MW minimum would be small enough that it would be economically inefficient to choose to build self-generation facilities. Such a minimum would be comparable to the maximum size of NIPSCO's other industrial power service rates intended for small industrial customers. Of course, no business or individual wants to pay costs they might otherwise avoid. But the benefits for this rate class that have already been approved are quite substantial and, in that context, raising the minimum demand level to a level commensurate with the size of these businesses can be simply viewed as a relatively minor mid-course correction.

V. DIVERGENCE BETWEEN ESTIMATES OF PEAK NON-FIRM LOAD FOR RATE 831 CUSTOMERS

Q: WHAT DOES NIPSCO'S COST OF SERVICE MODELING IN THIS CAUSE RECOGNIZE AS THE PEAK NON-FIRM LOAD FOR CUSTOMERS IN THE RATE 831 CLASS?

A: One can calculate that magnitude as the difference between the 4CP value of the Rate 831 firm load, shown as about 185 MW[10] at generation, and the 4CP[11] value for transmission load, shown as approximately 615 MW,[12] with that difference being 430 MW at generation.

---

[10] Shown in Attachment 19-D of Petitioner's Exhibit No. 19, page 2 of 40.
[11] Transmission costs are allocated by NIPSCO on a 12CP basis, but NIPSCO does a 4CP calculation for transmission demands in NIPSCO's document "NIPSCO Electric External Allocators_WORKPAPERS.xlsx" and I use that value to be comparable with the 4CP calculations for Rate 831 firm (Tier 1) demand.
[12] This value is found in cell P61 of the "CP Summary" tab of "NIPSCO Electric External Allocators_WORKPAPERS.xlsx."

Q: DID YOU OBTAIN THE ESTIMATES OF NON-FIRM LOAD AT PEAK THAT NIPSCO PROVIDES TO CUSTOMERS FOR PURPOSES OF PROVIDING TO MISO RELATED TO REGISTERING RATE 831 CUSTOMERS AS LOAD MODIFYING RESOURCES ("LMR")?

A: Yes. By September 30 of each year, NIPSCO supplies spreadsheets to each Rate 831 customer providing its estimate for each customer's "Zonal Resource Credit" ("ZRC")[13] for the MISO planning year commencing June 1 of the following year. Through discovery, I obtained[14] these spreadsheets for these estimates provided to Rate 831 customers in September of 2021 for MISO's planning year commencing June 1, 2022.

Q: WHAT WERE THE TOTAL ZRC ESTIMATES FOR RATE 831 CUSTOMERS FOR THAT PLANNING YEAR?

A: When I add up the individual ZRC values for each customer, but exclude the adder[15] reflecting added capacity needed to address MISO's planning reserve margin (to be comparable to the values shown in NIPSCO's cost of service calculations), I obtain a value of <<CONFIDENTIAL [redacted] CONFIDENTIAL>>than the analogous value for non-firm load at peak implied in NIPSCO's cost of service modeling in this Cause—a significant difference.

Q: IS THIS DIVERGENCE SMALL ENOUGH TO BE DISMISSED AS BEING DUE TO THE DIFFERENCE IN MISO'S APPROACH TO PEAK LOAD ESTIMATING?

A: No. While the load of these customers at MISO's coincident peak may be slightly different than their load at NIPSCO's coincident peaks and NIPSCO's value averages, I do not expect that difference to result in anywhere near the kind of divergence I just described. Also, while NIPSCO's method averages peak loads over 4 months, which is different than MISO's methodology, [16] Rate 831 customers have loads that should be relatively insensitive to variations in peak weather conditions from month to month. Thus, the divergence in these values cannot be readily dismissed as being caused by differences in methodology.

Q: WHAT DO YOU PROPOSE SHOULD BE DONE ABOUT THE DIVERGENCE BETWEEN THESE VALUES?

A: NIPSCO should perform and present an analysis harmonizing NIPSCO's estimate of peak non-firm load for Rate 831 customers with NIPSCO's estimates of these values created for purposes of provision to MISO for its planning reserve purposes. Completion of such an analysis is necessary

[13] ZRC is credit that fulfills a customer's requirement to present firm capacity to MISO.
[14] "Confidential Attachment A" to NIPSCO's response to OUCC DR 12-15.
[15] I use the values identified in these confidential spreadsheets as "Registered As LMR @ MISO (MW) by NIPSCO," which exclude MISO's required planning reserve margin.
[16] Explained in Section 3.2.2 of MISO Resource Adequacy Business Practice Manual.

for NIPSCO to have met its burden of proof as to the reasonableness of the cost allocations it proposes in this proceeding.

VI. RELIABILITY EFFECTS OF RATE 831

Q: WHAT POTENTIAL RELIABILITY EFFECTS PERTAINING TO RATE 831 CONCERN YOU?

A: First, I start with some explanation. From NIPSCO's perspective, Rate 831 is straightforward: provide a defined level of firm (Tier 1) load and transmission to serve that load for which NIPSCO is not obligated to provide as firm in Tiers 2 and 3. I have shown in the preceding section of my testimony that there is some discrepancy as to the amount of this load that needs to be addressed at peak conditions. No matter how that issue is resolved, it is clear there is a large amount of Tier 2 and Tier 3 load. This non-firm load is, by default, registered as an LMR at MISO or these customers can line up firm capacity for some or all of this load.

While this approach is easy from NIPSCO's perspective, it makes MISO's job of maintaining reliability more difficult. To the extent these customers register as LMRs, MISO has performance rules, which should ensure that these resources are available when called upon; however, these customers retain the right to obtain capacity in MISO's annual "Planning Resource Auction" ("PRA"). The load sizes of these customers, presumably along with uncertainties surrounding the amount of firm capacity sought by other entities in MISO's PRA, can have both financial and reliability implications. But even if these customers choose not to enter the auction and remain as LMRs for the year, the uncertainty of those decisions might lead potential capacity developers to hold off on building capacity that, depending on the decisions of these and other customers, might end up unneeded and/or depress the value of capacity from the current and succeeding auctions.

Q: DID YOU OBTAIN INFORMATION FROM NIPSCO ALLOWING YOU TO IDENTIFY THE AMOUNT OF FIRM CAPACITY LINED UP BY RATE 831 CUSTOMERS FOR MISO'S 2022-23 PLANNING YEAR THROUGH ITS PLANNING RESOURCE AUCTION?

A: Yes. I obtained MISO invoices for these customers presented to NIPSCO (as "Market Participant") for a number of days in summer of 2022. Those invoices show the daily dollar amount owed to MISO for capacity purchased through its PRA, and using the cost per MW-day from the auction results, I could identify the amount of capacity each Rate 831 customer purchased through that auction for the 2022-23 planning year.

Q: WHAT DID YOU IDENTIFY REGARDING THE AMOUNTS PURCHASED THROUGH THE PRA FOR THE 2022-23 PLANNING YEAR?

A: I determined <<CONFIDENTIAL [redacted] CONFIDENTIAL>>for the 2022-23 planning year.

Q: WHAT WERE THE RESULTS OF MISO PRA FOR THE 2022-23 PLANNING YEAR?

A: MISO issued a document on April 14, 2022[17] summarizing the results. That document reported a capacity shortfall for MISO's North/Central Regions and indicated that those entities purchasing capacity through the auction were exposed to the Cost of New Entry for the planning year. This result was apparently such a surprise that it caused one anonymous industrial customer to seek[18] to be excused from the obligation it incurred through its 2022-23 PRA purchase. The MISO document further notes "slightly increased risk of needing to implement temporary controlled load sheds."

Q: WHAT DO YOU TAKE FROM THOSE PRA RESULTS?

A: Surprises are not good when attempting to maintain the reliability of the grid. Clearly, there were several factors involved in the surprising results from MISO's 2022-23 PRA, but any material factors that lead to uncertainty as to the amount of firm capacity sought through MISO's PRA may be a source of concern as to the ability of MISO's system to produce a level of capacity necessary to maintain reliability. I expect that Tier 2 and Tier 3 load from NIPSCO's Rate 831, and whether that load will seek capacity through MISO's PRA, is one such factor.

Q: ARE YOU SAYING THAT YOU HAVE DETERMINED THAT RATE 831 TIER 2 AND TIER 3 LOAD PLAYED A FACTOR IN THE SURPRISING MISO PRA RESULTS?

A: No. I have not attempted to perform that analysis; I am concerned that the uncertainty introduced by Rate 831 may be playing a role. The fact that NIPSCO has eliminated its need to plan for Tier 2 and Tier 3 load does not mean there is no need to think about where this capacity will be coming from and whether MISO's capacity market design is up to the task of dealing with those uncertainties when combined with the other uncertainties MISO faces.

Q: WHAT ACTION DO YOU RECOMMEND RELATED TO THIS MATTER?

A: I realize these issues go beyond NIPSCO and Indiana, but it would be prudent to take whatever avenues are available to study what is happening in MISO capacity markets and the effect the Commission decisions have had and/or could have on those markets. To the extent it is determined

---

[17] Available at https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf.
[18] FERC Docket No. ER22-496-000 and as reported by Utility Dive at https://www.utilitydive.com/news/miso-ferc-midcontinent-exit-capacity-complaint/633482/.

uncertainties pertaining to Tiers 2 and 3 service under Rate 831 have had or will have a material effect, some restrictions and/or reporting related to the capacity decisions of these customers may be useful.

Q: DO YOU HAVE ANY OTHER RELIABILITY CONCERNS PERTAINING TO RATE 831 AND ITS SUCCESSOR RATE 531?

A: Yes. MISO Business Practice Manual 11 presents testing requirements that LMRs must meet to qualify that load for purposes of obtaining ZRC. Section 4.2.9.8 of MISO BPM-011-r26 states in part "If the DR[19] is unable to demonstrate performance of at least 50% of the registered MW capability during the testing period, the DR may still qualify for the PRA by opting out of the testing requirement, provided that the DR will then be subject to the three (3) times penalty provisions for underperformance described in Section 4.2.9." Given MISO, and by extension Indiana, is relying on the certain ability of LMR customers to reduce load when called upon for maintaining reliability, I am concerned that customers can "opt out" of those testing requirements if they are willing to take some financial risk. Especially in light of the tight capacity situation experienced in MISO's recent PRA, it seems unwise to allow a company's calculation as to the value of performing a test versus the potential for triple penalties to affect the reliability of the system.

Q: THOSE ARE MISO PROVISIONS, SO WHAT CAN THE COMMISSION DO ABOUT THIS MATTER?

A: It is my understanding from reviewing MISO publications that MISO often gives deference to state commissions when those commissions impose requirements that are stricter than MISO's. In this situation, I expect the Commission could impose a requirement in the Rate 831 tariff that any customers registering as LMRs must not achieve that status through opting out of any testing requirements, as such opting out would otherwise be available to the customer.

Q: DO YOU RECOMMEND THE COMMISSION MODIFY NIPSCO'S PROPOSED ARP AND RATE 831 TARIFF TO INCLUDE SUCH LANGUAGE?

A: Yes.

VII. <u>THE FUTURE</u>

Q: WHERE IS SERVICE OF NIPSCO'S LARGE INDUSTRIAL CUSTOMERS GOING?

A: Assuming and hoping, as the OUCC does, that NIPSCO's large customers maintain their competitiveness and their presence in Indiana, they will continue to need electric service. The

[19] The acronym for "Demand Resource" in MISO terminology.

Commission's order in Cause No. 45159, drawing on testimony from NIPSCO, speaks to a "transition" to implementing NIPSCO's preferred portfolio from its 2018 IRP. But that portfolio is silent as to how NIPSCO's largest customers will fulfill the great majority of their electric needs going forward. The assumption is, I suppose, "the market" will provide the electricity for these customers.

Q: IS "THE MARKET" UP TO THE TASK?

A: I do not think anyone really knows the answer to that question. MISO continues to make changes to ensure adequate capacity—the latest being its four-season capacity construct. But MISO's ability to incent the creation of adequate, reliable, and economic capacity has not really been tested, due to historic high levels of capacity among the largely vertically integrated set of utilities within its footprint. Its abilities are now being tested with the rapid retirement of controllable resources and their replacement with many intermittent resources. While we recognize the ability of most other markets in the United States to bring forth innovation and investment, whether MISO's market can bring forth a set of these resources that is both manageable and economic remains to be seen. On a cautionary note, I note the words of FERC commissioner James Danly in a concurring opinion issued August 22, 2022, in FERC Docket ER22-496-000, a docket in which MISO sought a "Minimum Capacity Obligation" ("MCO") to constrain the amount of capacity that Load Serving Entities can purchase through its PRA.

> Given both the challenges associated with navigating MISO's stakeholder process and what appears to be MISO's desperate need for reform of its capacity construct, the fact that MISO can file another MCO proposal is cold comfort.

He further states in that concurring opinion

> I also note that the reasons presented as the basis for this proposal have furthered my misgivings regarding MISO's capacity construct. Specifically, I am concerned by the increasing risk that MISO will be unable to retain sufficient dispatchable generation to ensure reliability and resource adequacy. With these concerns in mind, I urge my colleagues to consider Commission action pursuant to FPA section 206.

When utilities offload their problems onto MISO, then MISO must deal with those problems, and Commissioner Danly's statements reflect concerns about MISO's current ability in that regard.

Q: WHAT HAPPENS IF THE MARKET DOES NOT WORK OUT FOR RATE 831/531 CUSTOMERS AND THEY SEEK TO RETURN TO A STANDARD REGULATED TARIFF?

A: NIPSCO is performing its Integrated Resource Planning processes under the assumption they will not return. However, the tariff language provides for a five-year notice for a customer to increase firm (Tier 1) load.[20] While five years would likely be enough time to obtain sufficient capacity to serve these customers should they return, the generation system might be designed at that point in such a way that returning these large customers to the system would come at a cost to other customer classes. And NIPSCO could well seek recovery related to building those assets prior to the return of such customers. Specifically, I propose that NIPSCO be required file a notification with the Commission within 30 days of receiving any request to return to standard regulated rates of any Rate 831 customer. Further, NIPSCO should be required to file a plan showing how other rate classes would be held harmless from negative consequences of such a return, and a procedural schedule established to allow the OUCC and other interested parties discovery and the opportunity to present modifications to NIPSCO's plan.

VIII. RECOMMENDATIONS SUMMARY

Q: COULD YOU PLEASE SUMMARIZE THE RECOMMENDATIONS IN YOUR TESTIMONY?

A: Yes. I recommend:

1) That, grounded in the longstanding use of 12CP as the methodology approved by the Commission and the large effect on the residential production cost allocation factor that results from the change to a 4CP production cost allocation methodology approved in Cause No. 45159, and in the context of the OUCC's proposal for an across-the-board rate increase as proposed in the testimony of OUCC witness Glenn Watkins, that the Commission return to a 12CP production cost methodology for purposes of cost recovery in trackers that rely upon production cost allocation factors;
2) That language of NIPSCO's proposed ARP and related Rate 831 language be modified to prevent further reductions in Tier 1 load by either instituting a transition charge for further reductions as addressed in my testimony or through increasing the minimum Tier 1 demand required to participate in Rate 831, which I have suggested be 30 MW. The raising of the minimum Tier 1 demand should also be accompanied by modifications to other industrial rate classes to ensure that any current Rate 831 customers made ineligible under the raised minimum demand level would have an industrial rate for which they would qualify;

[20] "The Customer may increase the Tier 1 firm Contract Demand election with five (5) years' notice and a period of not less than five (5) Contract Years."

3) That NIPSCO be required to present an analysis addressing the divergence between estimates of Tier 2 and Tier 3 load implied in NIPSCO's cost allocation methodology versus those prepared for MISO LMR purposes;
4) That the Commission consider what is happening in MISO capacity markets and the effect Commission decisions related to Rate 831/531 have had and/or could have on those markets. To the extent it is determined uncertainties pertaining to Tiers 2 and 3 service under Rate 831 have had or will have a material effect, some restrictions and/or reporting related to the capacity decisions of these customers may be useful;
5) That the Commission impose a requirement in the Rate 831 tariff language that any customers registering as LMRs must not achieve that status through opting out of any testing requirements, as such opting out would otherwise be available to the customer;
6) That language of NIPSCO's proposed Rate 531 be amended to indicate NIPSCO will be required to file a notification with the Commission within 30 days of receiving any request to return to increase the Tier 1 service level of any Rate 831 customer. Further, that filing should include a showing as to how other rate classes would be held harmless from negative consequences of such a return, and a procedural schedule established that would allow the OUCC and other interested parties discovery and the opportunity to present modifications to NIPSCO's plan.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Peter M. Boerger, Ph.D.
Economics Workshop, LLC
Consultant for the
Indiana Office of Utility Consumer Counselor
Cause No. 45772
NIPSCO

Date
1/20/2023

Certificate of Service

This is to certify that a copy of the Indiana Office of Utility Consumer Counselor's Testimony Filing has been served upon the following parties of record in the captioned proceeding by electronic service on January 20, 2023.

Petitioner
Bryan Likins
Tiffany Murray
Debi McCall
NIPSCO, LLC
blikins@nisource.com
tiffanymurray@nisource.com
demccall@nisource.com

Nicholas Kile
Lauren Box
Lauren Aguilar
Hillary Close
BARNES & THORNBURG
nicholas.kile@btlaw.com
lauren.box@btlaw.com
laguilar@btlaw.com
hillary.close@btlaw.com

Walmart-Intervenor
Eric E. Kinder
Barry A. Naum
Steven W. Lee
SPILMAN THOMAS & BATTLE, PLLC
ekinder@spilmanlaw.com
bnaum@spilmanlaw.com
slee@spilmanlaw.com

IMUG-Intervenor
Robert M. Glennon
ROBERT GLENNON & ASSOC., P.C.
robertglennonlaw@gmail.com
With a copy to:
Ted.sommer@lwgcpa.com

U.S. Steel-Intervenor
Nikki Shoultz
Kristina Wheeler
BOSE MCKINNEY & EVANS, LLP
nshoultz@boselaw.com
kwheeler@boselaw.com
With a copy to:
lbood@boselaw.com

CAC-and Earthjustice –Intervenor
Jennifer A. Washburn
CITIZENS ACTION COALITION
jwashburn@citact.org
With a copy to:
sfisk@earthjustice.org
sdoshi@earthjustice.org
mozaeta@earthjustice.org
rkurtz@citact.org

NLMK-Intervenor
Anne Becker
LEWIS & KAPPES, P.C.
abecker@lewis-kappes.com
with a copy to:
atyler@lewis-kappes.com
etennant@lewis-kappes.com

NLMK Co-counsel
James W. Brew
STONE MATTHEIS XENOPOULOS & BREW
jbrew@smxblaw.com
With a copy to:
AMG@smxblaw.com

IG NIPSCO-Intervenor
Todd A. Richardson
Joseph P. Rompala
Aaron A. Schmoll
LEWIS-KAPPES, P.C.
trichardson@lewis-kappes.com
jrompala@lewis-kappes.com
aschmoll@lewis-kappes.com
with a copy to:
atyler@lewis-kappes.com
etennant@lewis-kappes.com

Midwest Industrial User's Group
James W. Hortsman
JAMES W. HORTSMAN LAW GROUP, LLC
jhortsman@hortsman.com

ChargePoint, Inc.-Intervenor
David T. McGimpsey
DENTON BINGHAM GREENBAUM LLP
david.mcgimpsey@dentons.com
With a copy to:
Connie.bellner@dentons.com

RV Group-Intervenor
Keith L. Beall
Clark, Quinn, Moses, Scott & Grahn, LLP
kbeall@clarkquinnlaw.com

Kelly Earls, Attorney No. 29653-49
Deputy Consumer Counselor
OFFICE OF UTILITY CONSUMER COUNSELOR
115 W. Washington St. Suite 1500 South
Indianapolis, IN 46204
Direct Line: 317.233.3235
Email: KeEarls@oucc.in.gov
infomgt@oucc.in.gov