FILED
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INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	**CAUSE NO. 45253**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

TESTIMONY OF

PETER M. BOERGER, PH.D – PUBLIC'S EXHIBIT NO. 9

OCTOBER 30, 2019

Respectfully submitted,

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**TESTIMONY OF OUCC WITNESS PETER M. BOERGER, PH.D.
CAUSE NO. 45253
DUKE ENERGY INDIANA, LLC**

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Peter M. Boerger, and my business address is 115 West Washington St., Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a senior economist, with the official job title of Senior Utility Analyst, in the Electric Division. A summary of my educational and professional background, as well as my duties and responsibilities at the OUCC, can be found in Appendix A.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to address a number of significant issues related to crediting revenues from and allocating costs related to Duke Energy Indiana, LLC's ("DEI" or "Petitioner") non-native sales. Additionally, I address DEI's proposed stacking methodology. Further, I provide perspective on DEI's proposed experimental rates for the Low Load Factor ("LLF") and High Load Factor ("HLF") rate classes.

Q: Please describe the examination and analysis you conducted in order to prepare your testimony.

A: I reviewed the petition, direct testimony and discovery responses presented by DEI related to the topics I cover in my testimony. I also participated in a number of teleconferences and meetings with DEI personnel.

Q: What topics does your testimony cover?

A: My testimony includes the following seven sections:

Section II: Provides a brief overview of terminology clarifying the concepts of "native" and "non-native" sales to aid in understanding the issues discussed in the sections to follow.

Section III: Considers DEI's proposals for changes to the tracking of revenue from non-native sales it makes into Midcontinent Independent System Operator ("MISO") energy and capacity markets ("MISO Markets"). I conclude that, in large part, those proposals should be rejected.

Section IV: Considers DEI's proposed crediting treatment for what it calls "short-term bundled non-native sales"—non-native sales that are negotiated rather than being conducted through MISO Markets. I conclude DEI should modify this proposal to credit a more reasonable amount of sales revenues to customers.

Section V: Presents an issue identified through review of the one "short-term bundled non-native sale" that DEI has made to date—that issue being the apparent lack of proper crediting of revenues from that sale. I conclude sales profits that should have been shared with customers from that transaction should be returned to customers in DEI's next Rider 70 proceeding.

Section VI: Considers DEI's proposed changes to its "stacking" methodology—the manner in which it allocates costs between "native" and "non-native" sales. I conclude the method proposed by DEI should be rejected in part.

Section VII: Considers DEI's proposed HLF and LLF "Experimental Rates," which grant benefits to a limited set of customers in exchange for cost-reducing behavior. I conclude the proposed experimental rates are reasonable so long as DEI collects adequate data in preparation for possible renewal or expansion of these rates.

Section VIII: Summarizes recommendations from the previous sections of my testimony.

Q: To the extent you do not address a specific item or adjustment, does this mean you agree with those portions of Petitioner's proposal?

A: No. Excluding any specific adjustments or amounts DEI proposes does not indicate my approval of those adjustments or amounts. Rather, the scope of my testimony is limited to the specific items addressed herein.

II. EXPLAINING "NATIVE" VS "NON-NATIVE" SALES

Q: What are DEI's "native" sales?

A: "Native" sales are electricity sales to customers who pay for DEI's production plant based upon the embedded cost of providing that service, as determined by the Indiana Utility Regulatory Commission ("IURC") and/or the Federal Energy Regulatory Commission ("FERC").

Q: What are DEI's "retail" sales and how do they relate to "native" sales?

A: "Retail" sales are sales to customers to whom DEI is obligated to provide service under Indiana law. Because retail customers pay for DEI's production plant based upon the embedded cost of providing that service, retail sales are one component of native sales.

Q: What comprises the other component of native sales?

A: A set of wholesale customers have historically entered into long-term contracts for service and voluntarily obligated themselves to pay for DEI's production plant based upon the embedded cost of providing that service. In exchange, DEI has historically taken on the responsibility of meeting the related supply obligations for those wholesale customers.

Q: Who are DEI's historical wholesale native load customers?

A: Three entities historically comprised wholesale native customers: Indiana Municipal Power Agency ("IMPA"), Wabash Valley Power Association ("WVPA"), and Hoosier Energy Rural Electric Cooperative ("Hoosier Energy"). These entities serve municipal or Rural Electric Membership Cooperative ("REMC") customers in Indiana.

Q: Is DEI's native wholesale load and the associated cost to serve that load under consideration in this Cause?

A: Yes, to a degree. While this case does not set rates for the wholesale native load customers, which is the responsibility of FERC, DEI presents a jurisdictional allocation study in this Cause that allocates costs between native wholesale and retail customers.

Q: What are DEI's "non-native" sales?

A: Non-native sales are sales to wholesale customers that have not committed to fund DEI's plant and operations on a regulated cost of service basis. Rather, they are wholesale sales priced based upon market forces—forces that do not necessarily result in prices fully covering DEI's embedded cost of service. While those sales might not fully cover DEI's average embedded cost of service, they can still benefit native load customers. Serving these customers will not require retail customers to pay for capacity, and the net profits (i.e. margins) earned on these sales, while not high enough to cover the full average embedded cost of production plant, can offset the costs native load customers would otherwise be obligated to pay.

Q: What types of "non-native" sales are relevant to DEI's proposals in this case?

A: It is useful to think of DEI's non-native sales (sometimes called "off system sales"[1]) in two categories—one category for sales that flow through MISO's established markets (either energy or capacity markets) and the other for sales that are bilateral in nature—transactions that are negotiated between DEI and another party. One category of such negotiated transactions is what DEI refers to in its Rider 70 testimony as "Energy or capacity sales to non-MISO counterparties..."[2] Another category of such negotiated transactions is what DEI presents in this proceeding as "short-term bundled non-native sales," which I will discuss in more detail later in my testimony.[3]

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[1] See Cause No. 42359, *Petition of PSI Energy, Inc. for Authority to increase its Rates and Charges for Electric Service*, Final Order, p. 55-56 (May 18, 2004). The Commission referred to such sales as "off-system sales."

[2] See e.g. Cause No. 44348 SRA-5, Direct Testimony of Scott A. Burnside, page 4, line 12 (September 14, 2018).

[3] See Petitioner's Exhibit No. 23, Direct Testimony of John A. Verderame, page 13, line 11, for his description of "short-term non-native bundled" sales. Petitioner's Exhibit No. 5, Direct Testimony of Suzanne Sieferman page 25, line 19, uses a slightly different phrase to refer to these sales as "short-term bundled non-native sales." I adopt in my testimony the phrase "short-term bundled non-native sales."

Q: Why do you draw a distinction between MISO Market sales and negotiated sales?

A: The importance of this distinction arises from the amount of initiative needed by DEI staff to maximize the value of generation assets—little to none in the case of market sales, but potentially significant in the case of bilateral sales. My discussion on the merits of DEI's non-native sales proposals will draw upon this distinction between non-native sales transacted through MISO Markets versus those transacted bilaterally and thus requiring initiative and negotiation.

Q: What mechanism does DEI use to calculate and flow non-native sales margin benefits to its retail ratepayers?

A: DEI uses its Rider 70, also known as "Reliability Adjustment" or "Summer Reliability Adjustment ('SRA')" rider (i.e. tracker), to present the computation of net non-native sales profits.[4]

III. DEI'S PROPOSED CHANGES TO TRACKING REVENUE RESULTING FROM NON-NATIVE SALES INTO MISO MARKETS

Q: How do the MISO Markets work?

A: MISO conducts its energy markets separately on both a day-ahead and real-time basis. Generation owners, such as DEI, offer their generation into these markets. Based on these offer prices, MISO selects generation resources in a manner that minimizes the cost of serving expected load. The annual MISO capacity market, also known as the Planning Resource Auction ("PRA"), matches capacity needs of load serving entities with generation owners willing to accept market prices for

[4] Cause No. 44348 SRA-5 is DEI's most recent Rider 70 filing, filed on September 14, 2018.

generation capacity not needed to serve their load, if any. As noted in DEI witness John A. Verderame's testimony, recent years' PRA prices, as compared to the embedded cost of owning the generating units, have been very low.[5] Importantly, there is an incentive in these markets to offer at or near the marginal cost of the units because offering the unit at too high a price means MISO may not select the units in the relevant market. This incentive is "automatic" in the sense there is little or no need to develop a different strategy to establish offers. Additionally, no negotiations are involved because the acceptance of offers in these markets is mathematically determined.

Q: How are DEI's non-native sales[6] profits currently handled for sales into those MISO markets?

A: Profits from non-native sales into MISO markets, as for any non-native sales, offset the cost of reliability purchases in DEI's Rider 70. In DEI's last base rate case (Cause No. 42359) the Commission authorized DEI to embed a credit of $18,700,000 for non-native sales profits as an offset to revenue requirement (less $3,953,000 for "fixed trading expense"), leaving a net $14,747,000 credit in rates.[7] The Commission ruled DEI would share 50/50, between shareholders and retail customers, in net non-native sales profits both above and below the embedded level.

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[5] Verderame Direct, page 14, lines 7 - 22.
[6] Non-native sales, included in DEI's computation of non-native sales profits, via Rider 70 refer to: 1) Day Ahead and Real Time Generation Sales to the MISO, which are allocated to non-native load; 2) Sales of capacity in the MISO PRA that do not offset reliability purchases; 3) Energy or capacity sales to non-MISO counterparties (*i.e.*, "bilateral sales") that do not offset reliability purchases; 4) Realized margin from non-native sales of emissions allowances; 5) Realized margin from non-native hedging activity; and 6) Non-firm retail contracts with Duke Energy Indiana customers. *Also See* Cause No. 44348 SRA-5, Direct Testimony of Scott A. Burnside, page 4.
[7] Verderame Direct, Petitioner's Exhibit 23-A (JAV).

The Commission also ruled DEI could not recover any net non-native sales losses over the annual tracker period (for Rider 70 purposes, non-native sales profits can never be less than zero dollars).

Q: What changes is DEI proposing related to its treatment of non-native sales through Rider 70?

A: DEI is proposing two changes:

1) Eliminating past practice of embedding an amount of non-native sales margins while retaining 50/50 sharing of profits; and
2) Eliminating the provision found in DEI's current Rider 70 prohibiting recovery of net non-native sales losses over the annual rider period.

Q: What is the OUCC's position on resetting the base amount of test year non-native sales to zero?

A: The OUCC does not oppose resetting the base amount to zero for this type of sale; however, if the Commission approves that change, it is important from a fairness perspective that retail customers receive 100% of non-native sales margins resulting from sales into the MISO Markets, rather than maintaining the 50/50 sharing DEI proposes.

Q: Why is it good regulatory policy for consumers to receive 100% of margins from non-native sales made into the MISO Markets?

A: DEI's retail customers are paying for the generating assets and for DEI's infrastructure used to interface/transact with MISO as part of the revenue requirement in this case. Therefore, absent a good reason to the contrary, customers deserve 100% of non-native sales margins resulting from the sale of energy and/or capacity in the MISO Markets. Before the advent of MISO Markets, the maximization of non-native sales required a significant amount of personal interactions, marketing activity and negotiation with potential counterparties. Under those circumstances, financial incentives such as sharing above and below a base embedded amount were useful. However, as discussed above, the advent of MISO Markets has eliminated the need to interact with counterparties for sales into the market, and the market design essentially eliminates the utility's ability to increase non-native sales margins through its own actions. For these reasons, a justification for sharing non-native sales margins with the utility for sales made into MISO Markets no longer exists and customers should receive 100% of these profits.

Q: In the alternative, would it be reasonable to continue with the method approved in DEI's last base rate case—embedding a test year amount for non-native sales with 50/50 sharing?

A: No. As just explained, no benefit arises from a 50/50 sharing incentive above and below an embedded non-native sales profit amount for non-native sales made into the MISO Markets. For this type of market-based sale, DEI's offer strategy and decisions regarding unit commitment should be grounded in a technical approach to minimizing the cost of providing native load service, which provides no real opportunity for profit-maximizing decisions or behavior. Providing financial incentives related to market sales would, if anything, only serve to provide incentives for uneconomic behavior, such as changing unit commitment decisions to increase non-native sales margins at the expense of overall cost minimization. Given the reality of what I describe above as an "automatic" approach to non-native margins provided through MISO Markets, it is no longer appropriate to provide this kind of 50/50 financial incentive.

Q: What is DEI requesting regarding recovery of negative margins on non-native sales into the MISO energy market?

A: In his testimony, Mr. Verderame states, "The Company . . . proposes that Customers share fully in positive as well as potentially negative margins from non-native sales."[8]

Q: How does that approach differ from the one approved in DEI's last base rate case?

A: In the order approving rates in DEI's last base rate case, the Commission restricted the crediting of non-native ("off-system") margins stating, "PSI may not apply a net annual off-system sales profit of less than zero to the tracker."[9]

Q: How does DEI explain the appropriateness of recovering negative non-native sale profits?

A: Mr. Verderame states ". . . the Company has experienced periods of negative non-native margins. These negative margins generally occur for short periods during off-peak hours, when market prices are below marginal costs, but native load requirements fall below actual generation levels."[10] Mr. Verderame further states these losses occur ". . . in the larger picture of committing long lead-time units so that they are available for native customers…"[11]

Q: Do you find Mr. Verderame's response compelling?

A: No. The motivation for any business selling goods is to earn a profit; as such, it is right for the Commission to view skeptically the recovery of losses on sales of power. While there will be hours in which the utility will earn negative margins as

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[8] Verderame Direct, page 16, lines 6 - 7.
[9] Cause No. 42359, Final Order, page 117 (May 18, 2004).
[10] Verderame Direct, page 18, lines 17 - 20.
[11] Verderame Direct, page 18, line 21 through page 19, line 1.

part of a reasonable unit commitment strategy, Mr. Verderame's language gives the impression the Commission's prohibition applies to any hour in which a loss occurs, which is not the case. As is clear from the computation included in the current tariff Rider 70 sheet, the Commission's prohibition on recovering sales losses only applies to net amounts accumulated over the course of a year. To accumulate a loss over an entire year, when selling a product that on first principles should be earning a profit, is much more difficult to explain than losing money in particular hours, as Mr. Verderame describes.

Q: What is the OUCC's position regarding DEI's request to recover negative non-native sales profits accumulated over the course of a year?

A: While I cannot say accumulating a loss on non-native sales over an entire year can never result from utility operations that are part of a reasonable strategy of committing DEI units, the accumulation of a net loss over a year should, at a minimum, place a high burden on DEI to show the accumulated losses were justified. Unless DEI provides additional evidence of the reasonableness of the commitment of its units over the rider period, it should be presumed that accumulated losses are not recoverable. While adding that requirement would makes DEI's proposal more reasonable, such additional evidence would place an added burden on the OUCC and the Commission to review that additional evidence in the rider proceeding, which is intended to be expedited in nature. Additionally, excluding the effects of fixed trading expenses (which DEI is not proposing to continue as part of Rider 70), Petitioner's Exhibit 23-A (JAV) shows that losses have been infrequent and small in the context of DEI's overall revenues. Thus, from a practical standpoint and as an alternative to the "additional evidence" standard just discussed, the Commission could reasonably choose to continue the prohibition on recovery of accumulated annual non-native sales losses, as was ordered in DEI's last base rate case.

IV. "SHORT-TERM BUNDLED NON-NATIVE SALES" MARGINS

Q: What are "short-term bundled non-native sales," as described in Mr. Verderame's testimony?

A: Mr. Verderame presents the "short-term bundled non-native sales" concept in contrast to traditional native load sales DEI made to Indiana entities IMPA, Hoosier Energy and WVPA in past decades.[12] He states such entities no longer wish to enter into native load contracts wherein DEI commits to plan for capacity to serve them in exchange for payment reflecting DEI's fully embedded cost of generation. In contrast, sales into MISO Markets provide little contribution to DEI's fixed costs at current market prices. Thus, DEI presents in this case "short-term bundled non-native sales" as implementing a kind of 'middle ground' strategy in which it can earn more revenue than MISO Markets would provide. While that revenue is not enough to cover DEI's average embedded cost of generation, DEI will not be required to plan for generation resources to serve such "short-term bundled non-native sales" beyond the proposed maximum 5-year contract length.

[12] Verderame Direct, page 12, lines 3 - 14.

Q: How does DEI propose crediting revenues from "short-term bundled non-native sales" to its native load customers?

A: DEI proposes to credit "short-term bundled non-native sales" revenues to customers in the same way it proposes to credit net profits resulting from traditional non-native sales into the MISO Markets—embedding zero dollars in base rates and sharing revenues with native load customers on a 50/50 basis.

Q: Does the OUCC find it reasonable to use "short-term bundled non-native sales" as a strategy for DEI to increase revenue from its excess generation capacity?

A: Yes. The OUCC recognizes that, at this time, MISO Markets do not provide revenues anywhere near the average embedded cost of DEI's generation.[13] To the extent DEI cannot find customers willing to pay for its power at or near the full average embedded cost of its generation, the concept of "short-term bundled non-native sales" appears to be a reasonable approach, so long as DEI ensures these contracts do not require it to plan added capacity for providing such service.

Q: Does the OUCC agree with DEI's proposed mechanism for crediting "short-term bundled non-native sales" revenues?

A: No. As I explained earlier pertaining to sales into MISO Markets, ratepayers, through base rates, are paying for the fully embedded cost of DEI's generating facilities. While some incentive to maximize the value of its excess capacity may be appropriate, it would be unfair for DEI to receive anywhere near half of the non-native sales revenues those facilities generate.

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[13] Verderame Direct, page 11, line 11 through page 12, line 22, contains a summary of the state of MISO Markets.

Q: Does the OUCC believe it is appropriate for DEI to be provided an incentive, to a smaller extent, pertaining to "short-term bundled non-native sales" revenues?

A: Yes. These sales are different from those made into MISO Markets. As discussed earlier, DEI should be actively marketing its excess capacity for sales outside of MISO's markets and will need to negotiate to obtain the highest revenues possible for those sales. Thus, the OUCC prefers DEI have an economic stake in the revenues received. While 50% is too much compensation for incremental sales, an 80/20 sharing (80% retail customers and 20% shareholders), should in my opinion be sufficient to motivate DEI to maximize revenue from these sales. DEI should also embed a reasonable amount of sales revenue as an offset to revenue requirement in its base rates resulting from this rate case.

Q: What amount should DEI embed in base rates to reflect "short-term bundled non-native sales" and to offset revenue requirements in this case?

A: As identified in Ms. Sieferman's and Mr. Verderame's testimony, DEI has already entered into one "short-term bundled non-native sale"[14] The OUCC reviewed the contract for that sale and determined it covers the test year in this case. The net revenue from that sale would, in my opinion, provide a reasonable offset to DEI's revenue requirement in this case. To the extent DEI's revenue in years after the test year exceed that amount, it would through this mechanism receive 20% of that excess revenue and, to the extent "short-term bundled non-native sales" (in addition to any other non-market, non-native sales) fall below that level, DEI would cover

[14] Verderame Direct, page 15, lines 1 - 4 and Sieferman Direct, page 26, lines 9 - 10.

20% of that shortfall—providing a significant incentive to proactively market its excess capacity.

Q: What is the dollar value of that offset to revenue requirement?

A: Ms. Sieferman, for purposes of implementing DEI's proposed approach to crediting "short-term bundled non-native sales," identifies revenue from the one existing sale as $23,976,000,[15] and the fuel expense related to the sales as $11,234,000,[16] leaving a net margin credit to embed in base rates and offset revenue requirement of $12,742,000.

Q: Does DEI propose incorporating that margin as an offset to revenue requirement in this proceeding?

A: No. Witness Sieferman explains that DEI is proposing to include the margin from the one existing sale in its Rider 70, with the margin shared equally between DEI and its customers. She states this proposal ". . . provides a way for retail customers to realize a benefit . . . from these sales. . ." [17]

Q: Do you agree with DEI's proposed approach?

A: No. Ms. Sieferman's testimony makes it sound as though DEI is providing an undeserved benefit to ratepayers by allowing them to share in this margin. The reality is ratepayers are fully funding the generation capacity that makes this sale possible. Therefore, DEI can make no reasonable claim to a share of that margin in this rate case. As I discussed above, the OUCC is recommending an incentive to DEI regarding "short-term bundled non-native sales"; however, that incentive is

[15] Sieferman Direct, page 9, line 14.
[16] Sieferman Direct, page 10, line 19.
[17] Sieferman Direct, page 27, lines 2 - 7.

reasonable only if an appropriate amount of margin is embedded in rates. Fortuitously, Ms. Sieferman provides adjustments in her testimony that make the amount to embed in rates easy to calculate, as I have presented above. While this approach deals reasonably with the DEI's approach to dealing with the margin from its one existing "short-term bundled non-native sale" coming out of this rate case, its past approach to crediting revenue from this one sale has been inappropriate, as I will discuss next.

V. REFUND OF SHORT-TERM BUNDLED NON-NATIVE SALES PROFITS

Q: What additional matter do you have related to DEI's one existing short-term bundled non-native sale?

A: In the previous section of my testimony I discussed the test year treatment of the one "short-term bundled non-native sale" DEI entered into to date, and recommended that the margin from that transaction be included as an offset to base rates in the test year. In reviewing DEI's transaction, I identified concerns with DEI's treatment (or lack of treatment) of that sale in its most recent Rider 70 proceeding and with how DEI proposes the margin from that sale will be treated through the time that new base rates are established as a result of the current rate case.

Q: What concern do you have with DEI's treatment of margin from that transaction?

A: That transaction should have been accounted for as part of the tracking of the off-system sales profits through the sharing mechanism approved as part of DEI's Rider 70 in its last base rate case (Cause No. 42359). The sale was not a native load sale and, as such, can reasonably only be interpreted as an "off-system" sale and thus subject to the 50/50 sharing mechanism approved in DEI's last rate case.

Q: How do you know the short-term bundled non-native sales transaction was not included in DEI's SRA-5 proceeding as part of its sales profits for that period?

A: Ms. Sieferman, in this rate case, testifies ". . . no ratemaking impacts have been recognized to date for customers as a result of this one particular contract."[18]

Q: Was the OUCC made aware of this transaction at the time of the SRA-5 proceeding?

A: No. This transaction was not addressed in the testimony of DEI in that proceeding and, to my knowledge, no one at the OUCC was made aware of this transaction or DEI's treatment of it as part of that proceeding or at any other time until it was disclosed as part of the current rate case. Because DEI did not address this transaction in its SRA testimony, nor bring this transaction to the OUCC's attention, the OUCC did not have the opportunity to challenge DEI's decision to not share profits in the SRA-5 proceeding.

Q: What explanation has DEI provided in testimony in this case regarding why profits from this transaction were not shared with customers through Rider 70?

A: The only explanation comes from Ms. Sieferman's testimony where she states, "Between retail rate cases, the Company has not updated its cost of service study and therefore no ratemaking impacts have been recognized to date for customers as a result of this one particular contract."[19] I understand this statement to mean DEI

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[18] Sieferman Direct, page 26, lines 19 - 20.
[19] Sieferman Direct, page 26, lines 18 - 20.

did not share the margins from this transaction with customers due to the fact that DEI had not updated its cost of service study since its last base rate case.

Q: Does that explanation make sense?

A: No, it does not. A cost of service study determines how costs are allocated between retail and wholesale native load customers (in a jurisdictional cost of service study) or between retail rate classes (in a retail class cost of service study). The existence or nonexistence of an update to either one of those types of cost of service studies has no bearing on whether the margin from this non-native load sale should have been shared with customers through Rider 70. The language in the order in DEI's last base rate case authorizing Rider 70, and the language in its current Rider 70, do not contain an exclusion related to sharing non-native load sales profits with customers in transactions such as the one at issue here. The reasoning presented in Ms. Sieferman's testimony does not address this basic fact and, as such, she has not provided a reasonable explanation for the treatment of margins from this transaction.

Q: What does the OUCC recommend to the Commission to address DEI's unjustified treatment of the profits from this transaction?

A: Due to DEI's inappropriate treatment of those profits, the OUCC recommends the Commission order DEI to return the amount of profit that should have flowed to customers in SRA-5, back to ratepayers. Sharing of profits from this transaction should also occur for the time period following the SRA-5 reconciliation period through the date base rates are changed as a result of the current rate case. Following that date, no further refunds will be needed since the recommendations

I present earlier in my testimony regarding treatment of this transaction in determining DEI's base rates will resolve the issue going forward.

Q: Does the OUCC's refund request represent retroactive ratemaking?

A: No. The proposed refund does not change the rules after the game has been played, it is simply enforcing the rules that the Commission previously set and that were not followed by the utility or brought to the OUCC's attention so that it could have been addressed in the SRA-5 proceeding.

Q: How does the OUCC propose implementing the refund?

A: Rather than ordering a specific dollar amount in this proceeding, the OUCC recommends that the Commission require DEI to present, in its upcoming rider proceeding(s), a calculation of the profit sharing that would have occurred from June 1, 2017 through the time its base rates are changed in this Cause. This calculation should properly account for this transaction's profits as being subject to the profit sharing provision for non-native load sales in Rider 70 ordered in DEI's prior base rate case, Cause No. 42359. That calculation would then be the subject of adjudication in the Rider 70 proceeding(s).[20]

VI. DEI'S PROPOSED "STACKING" METHODOLOGY CHANGES

Q: What is "stacking" as it pertains to DEI's case?

A: "Stacking" is the allocation of fuel costs to native and non-native load for generation sales into MISO's energy market.

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[20] The timing of DEI's rider 70 proceedings would determine the number of such rider 70 proceedings in which these refund calculations would need to be presented.

Q: What approach are utilities expected to take when allocating costs between native and non-natives sales?

A: Sound utility practice dictates that utilities are expected to allocate their lowest cost sales to native load, with higher cost generation sales supporting non-native sales into the MISO energy market.

Q: Does DEI accept that stacking approach?

A: Yes, it appears so with one exception, which I will discuss later in this section of my testimony.

Q: What stacking methodology changes is DEI proposing?

A: DEI proposes to allocate a portion of certain generating units' fuel costs—the portion called "no-load costs"—to native load customers, rather than allocating them to both native and non-native sales. That change will have the effect of adding to the amount of fuel cost allocated to its native load customers.

Q: What are "no-load costs"?

A: "No-load costs" are the costs that represent the amount of fuel needed to spin the generating unit with zero output—essentially the cost of overcoming frictional losses in the unit.

Q: Are DEI's no-load costs significant?

A: Yes. I met[21] with DEI personnel and reviewed confidential cost information. As a result of that review, I can report that "no-load costs" represent a significant share

[21] Meeting at DEI's Plainfield offices on October 3, 2019.

of the fuel cost to operate the units to which DEI wishes to apply its proposed stacking rules.

Q: What is DEI's justification for allocating "no-load costs" to native load customers?

A: Mr. Verderame explains that a no-load cost is a "sunk cost" and remains the same regardless of unit loading.[22] He goes on to present that, "[g]enerally, the minimum load block of long-term commitment units will be allocated to native load,"[23] and it is "appropriate to allocate this cost to native load given that native load will be entitled to the first call on all generation resources, and these units are committed for the benefit of native load."[24] Additionally, he states that DEI's proposal "will align post-analysis results and actual dispatch logic used by MISO,"[25] with MISO dispatching units based on incremental cost (which excludes no-load costs) rather than on average cost (which includes no-load costs).

Q: Do those arguments persuade you of the appropriateness of the change DEI is proposing?

A: No. MISO dispatches units based on incremental cost, which is appropriate because that approach will lead to a least cost dispatch. However, changing DEI's stacking does not change MISO's dispatch of DEI's generating units; DEI's proposal changes cost allocations only after the fact. Because there is no change to the manner in which MISO dispatches DEI's generating units there is no improvement

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[22] Verderame Direct, page 22, lines 13 - 22.
[23] Verderame Direct, page 23, lines 10 - 11.
[24] Verderame Direct, page 23, lines 12 - 15.
[25] Verderame Direct, page 23, lines 20 - 21.

in efficiency resulting from DEI's proposal. Therefore, with no improvement to operational efficiency resulting from DEI's proposal, the evaluation of its stacking proposal must come down to whether it is more fair[26] for more no-load costs to be allocated to native load customers compared to non-native sales. Based upon my review, I must conclude there is no improvement in fairness resulting from allocating more "no-load" costs to native load customers as proposed by DEI, as I will next discuss.

Q: Does economics provide guidance as to the fairness of allocating sunk costs such as "no-load" costs?

A: No. The "positive" or "prescriptive" side of economics only speaks to the efficiency of using incremental costs rather than average costs; for any change that does not affect the efficiency of resource allocation, economics is silent. As I just explained, there is no improvement in cost allocation from DEI's proposal and, as such, there is no basis in economic theory for allocating more no-load costs to native kWh than to non-native kWh.

Q: Can we gain insight as to how "no-load" costs should be allocated from the way that other utility costs are allocated in a base rate case?

A: Yes. I find a useful precedent in the standard cost of service methodology used to allocate joint, fixed costs incurred in providing utility service. That standard methodology addresses the difficulty of determining which customers are "marginal" by simply allocating on an "average" basis, using measures grounded

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[26] Verderame Direct, page 23, lines 21 – 22, which states that DEI's proposal will "more equitably and appropriately allocate fuel cost between native and non-native sales," which is a claim that the proposed methodology change is more fair.

in usage, such as kW demand. The allocation of no-load cost is similar to the problem of allocating all other costs incurred in a utility's operation and, as such, there is no reason to depart from the standard methodology of allocating costs on an average basis, which is the methodology that DEI seeks permission to change in this case.

Q: Does the OUCC recommend rejecting DEI's proposed change to its stacking methodology related to no-load cost?

A: Yes, that is correct.

Q: Is there another component to DEI's fuel cost allocation methodology proposal?

A: Yes. DEI proposes to eliminate its "two-pass" stacking methodology in which native load customers are prevented from having access to DEI's lowest cost fuel resources as they are ultimately realized in MISO's real-time market.[27] This denial of access arises from DEI's decision to allocate unit output based on day-ahead market prices, which then restricts native load from claiming lower cost generation that might arise due to the results of real-time operations. Eliminating this two-pass methodology will ensure native load customers are not restricted from receiving DEI's lowest cost resources, as should be the case.

Q: Does the OUCC support elimination of that two-pass stacking methodology?

A: Yes. It appears DEI previously instituted a methodology that restricts native load customers from always claiming its lowest cost resources, and its proposal to eliminate that methodology is good. Mr. Verderame's testimony appears to

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[27] Verderame Direct, page 24, lines 1 - 15.

indicate DEI wishes to tie elimination of the two-pass methodology to approval of the stacking proposal I previously identified as being inappropriate, stating "[u]nder incremental cost stacking, the two-pass process unnecessarily complicates cost allocation."[28] I see no reason to tie approval of the elimination of DEI's two-pass methodology to approval of its no-load cost allocation proposal.

VII. HLF AND LLF EXPERIMENTAL RATES

Q: What are the HLF and LLF experimental rates DEI is proposing in this proceeding?

A: DEI proposes two new rate "programs"[29] for certain HLF and LLF customers. An "Experimental Market Pricing Program" would allow customers access to wholesale market prices in exchange for shifting load from higher cost to lower cost periods and/or for increasing load in a manner that does not increase the utility's need for capacity. An "Experimental Demand Management and Stability Program" also grants some access to wholesale market prices. However, in this program, such access is granted in exchange for interruptibility and for commitments related to non-coincident peak demand over a five-year contract period, with penalty provisions included for noncompliance with commitments. Each of these programs is limited to 100 MW in aggregate demand and each expires on December 31, 2025.

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[28] Verderame Direct, page 24, lines 7 - 8.

[29] Revised Petitioner's Exhibit No. 8, Direct Testimony of Jeffrey R. Bailey, page 21, line 16 through page 23, line 12; Revised Petitioner's Exhibit No. 9, Direct Testimony of Roger A. Flick, II, Petitioner's Exhibit 9-A, Sheets 97 and 98.

Q: Does the OUCC object to these programs allowing access to MISO wholesale prices?

A: While the OUCC is generally concerned about granting access to prices that are not grounded in the utility's cost of service and that could cause other rate classes to subsidize such access, the OUCC does not object to these programs because they are designed in a way that limits their effects on fixed cost recovery, if any, to the LLF and HLF rate classes, are limited in magnitude (100 MW each), and are limited in duration. By not reducing cost allocations to these rate classes to reflect these experimental programs, DEI is putting its own fixed cost recovery at stake in the hopes of incenting cost-reducing behavior on the part of program participants. Under those design parameters, the OUCC does not object to a limited program granting the proposed wholesale market access.

Q: Does the OUCC request the Commission place requirements on DEI as part of approving these rates?

A: Yes. With these programs presented as "experimental," and DEI potentially coming back to the Commission to extend and/or expand the programs, it seems appropriate to require DEI collect data on customers' behavior and to study the effects of any behavioral changes on its cost of providing service. DEI should be required to present the data and related analysis at the time a request to extend or expand these programs occurs.

VIII. RECOMMENDATIONS

Q: Please summarize your recommendations for each topic covered in your testimony.

A: I recommend:

1) Non-native sales into MISO Markets: Allocate 100% of profits to retail customers from a zero base instead of the 50/50 sharing proposed by DEI. Regarding recovery of annual negative sales profits, I recommend either continuing to deny recovery of such net losses or implementing a rebuttable presumption that annual losses on such sales are not recoverable;

2) "Short-term bundled non-native sales": Embed non-native sales margin credit of $12,742,000 from DEI's one such bundled sale in base rates to offset its revenue requirement, with 80/20 (retail customers/shareholders) tracking above and below that amount in Rider 70. This mechanism would apply to any negotiated non-native bilateral sale, whether or not such sale would fall under DEI's definition of "short-term bundled non-native sales";

3) Refund past sharing of bundled margins not provided to native load customers: DEI should be ordered to refund margins not provided to native load customers from its one short-term bundled sale in its next Rider 70 proceeding(s);

4) Stacking methodology: DEI's request to allocate more no-load cost to native load customers should be rejected; however, its request to

eliminate its two-pass allocation methodology should be approved; and

5) HLF and LLF experimental rates: Approve DEI's request for these experimental rates, under the condition DEI collect and analyze data prior to coming back with a request to renew or expand these programs.

Q: Does this conclude your testimony?

A. Yes.

APPENDIX A - QUALIFICATIONS OF PETER M. BOERGER, PH.D.

Q: Please summarize your professional background and experience.

A: My undergraduate education consisted of a Bachelor of Science degree in Mechanical Engineering from the University of Wisconsin-Madison and a Bachelor of Arts degree in Physics from Carthage College, through its 3-2 engineering program. The extra year of liberal arts study during my undergraduate career allowed me to take significant coursework in business and economics, including courses in microeconomics, macroeconomics and accounting. After working as an engineer at a manufacturing company, my graduate training began at Purdue University (West Layette campus) in a program of Technology and Public Policy, resulting in a Master of Science in Public Policy and Public Administration. My training there included courses in microeconomic theory, cost-benefit analysis, operations research (cost minimization algorithms as might be used in utility economic optimization programs), and policy analysis. I came to Indianapolis and worked doing research and analysis at Legislative Services Agency and later at the Indiana Economic Development Council. Following those stints, I began working on my Ph.D. at Purdue University (West Lafayette campus) in Engineering Economics through Purdue's School of Industrial Engineering. That program required taking Ph.D.-level microeconomics classes, as well as additional work in operations research. During my time there I taught a 300-level engineering economy class for three semesters. While finishing my doctoral thesis I worked in policy research for the Indiana Environmental Institute in Indianapolis and then, after obtaining my doctorate, went to work at the Indiana Office of Utility Consumer Counselor, starting as an economist in the Economics and Finance Division. During my 8 years there, I rose to Assistant Director of the Electric Division and then Director of that Division. In 2005 I left the Agency to pursue other interests, largely outside of utility regulation, and then returned in November of 2015 to work in my current position as a senior economist in the Electric Division, with the formal title of Senior Utility Analyst.

Q: Please describe your duties and responsibilities at the OUCC.

A: I review petitions submitted to the Commission for their economic justification and perform other duties as assigned by the Agency.

Q: Have you previously testified before the Commission?

A: Yes, I have testified before the Commission in a number of significant cases during the 1997 to 2005 time frame. I also recently submitted testimony in a number of proceedings since my return to the agency.

AFFIRMATION

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

Peter M. Boerger, Ph.D
Senior Utility Analyst
Indiana Office of Utility Consumer Counselor
Cause No. 45253
Duke Energy Indiana, LLC

October 30, 2019
Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 30th day of October to the following:

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