BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE, THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

EXCEPTIONS AND PROPOSED ORDER OF THE KROGER CO.

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ATTORNEYS FOR THE KROGER CO.

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EXCEPTIONS AND PROPOSED ORDER OF THE KROGER CO.

The Kroger Co. ("Kroger") submits its Exceptions and Proposed Order in support of its recommendations with respect to Indiana Michigan Power Company's ("I&M" or the "Company") Petition for authority to increase rates. For ease of use, Kroger's Proposed Order includes page references to the outline established in I&M's November 11, 2019 Proposed Order.

ARGUMENT

I. LGS RATE DESIGN

A. The Commission Should Approve A Rate Design For the LGS Tariff That Improves The Alignment Between Charges And The Underlying Costs While Employing The Principle Of Gradualism.

I&M's LGS rate serves medium to large sized business customers with monthly billing demands between 60 kVA and 1,000 kVA.[1] Kroger's critique of the LGS rate design in this case has focused on the fact that I&M

[1] I&M's demand related charges are levied through both a per/kVa (demand) charge and a load factor blocking mechanism with the Block 1 rate applied to the first 300 kWh per kVA, and the Block 2 rate applied to billed energy over 300 kWh per kVA.

recovers a large portion of demand-related costs though energy charges both in the current LGS design and in I&M's proposed LGS design. This is shown using I&M's own cost of service data. The Table below was prepared by Kroger witness Justin Bieber and shows the LGS rate schedule charges relative to costs by classification for I&M's proposed rate design:[2]

I&M Proposed Charges Relative to Costs for the LGS Rate Schedule at I&M's Proposed Revenue Requirement

Classification	I&M Charges/Costs
Demand	49.6%
Energy	443.5%
Customer	105.5%

As shown above, I&M's proposed rate design for the LGS rate schedule significantly under-recovers demand-related charges while significantly over-recovering energy-related charges relative to the underlying costs. I&M witness, Mathew Nollenberger stated during cross-examination that he agreed with Mr. Bieber's conclusion that only about 50% of demand related costs are recovered from demand charges in I&M's proposed LGS rate design:

> "***Q.*** *[Y]ou generally agreed with [Mr. Bieber's] analysis?*
>
> ***A.*** ***[Mr. Nollenberger]*** *The results, yes, that - - the percentages that he lays out for demand energy and customer classified costs, I do.*
>
> ***Q.*** *And this analysis shows that your proposal would have about 50 percent of demand-related costs recovered through demand charges; is that correct?*
>
> ***A.*** ***[Mr. Nollenberger]*** *Within rounding, I confirmed that that's about right, yes.*"[3]

From an LGS customer's perspective, this under-recovery of demand related costs through demand charges is a major problem because when demand charges are set below cost, and energy charges are set above cost, those customers with relatively higher load factors are required to subsidize the lower load factor customers within the class. Aligning rate design with underlying cost causation is important for ensuring equity among customers, because properly aligning charges with costs minimizes these cross-subsidies among customers. It also improves efficiency because it sends proper price signals.[4] Mr. Nollenberger recognized the importance of aligning rates

[2] See Direct Testimony of Justin Bieber, p. 9.
[3] See Transcript of Hearing on October 16, 2019, Page H-80.
[4] Direct Testimony of Justin Bieber, p. 10.

with costs in his discussion regarding the inherent problems with I&M's current residential tariff. Mr. Nollenberger states that a misaligned rate design can introduce intra-class subsidies paid by high energy users to low energy users.[5] In light of these considerations, Kroger respectfully requests that the Commission address the misalignment of costs and charges within the LGS rate class in this proceeding.

Kroger agrees with Mr. Nollenberger that moving LGS rates 100% to cost-based rates would not be reasonable,[6] so instead Kroger proposes that the Commission make a more modest movement toward cost-causation so that about 65% of demand-related costs are recovered through demand charges. This can be achieved by making a change to the LGS Block 1 and Block 2 energy charges.[7] Specifically, I&M's proposed LGS rate design sets the secondary LGS Block 1 rate equal to 90% of the GS Block 2 rate and the resulting LGS rate design has a Block 1 rate differential premium of $0.02415 relative to the LGS Block 2 charge.[8] This differential is substantially less than I&M's proposed GS Block 1 energy rate differential premium. As described in Mr. Bieber's Direct Testimony,[9] Kroger recommends that the differential between the LGS Block 1 and Block 2 rates for the secondary voltage sub-class be increased so that it is set equal to the differential between the GS Block 1 and Block 2 secondary rates. The differentials for the other voltage sub-classes will vary slightly due to I&M's proposed loss factor adjustments. Kroger does not recommend any changes to I&M's proposed LGS demand or customer charges at this time. The revenue verification for this rate design is attached to Mr. Bieber's Direct Testimony and marked as Exhibit JDB-1. The proposed rates are shown in Table below.[10]

Kroger Proposed LGS Rate Design
at I&M's Proposed Revenue Requirement

	Demand Charge	Energy - Block 1	Energy - Block 2	Monthly Service Charge
Secondary	$6.711	$0.08088	$0.04180	$35.30
Primary	$4.547	$0.07858	$0.04060	$159.20
Subtransmission	$1.312	$0.07752	$0.04006	$159.20
Transmission	$1.296	$0.07670	$0.03964	$159.20

[5] Direct Testimony of Matthew Nollenberger, pp. 14-15.
[6] Rebuttal Testimony of Mathew Nollenberger, pp.15-16.
[7] Direct Testimony of Justin Bieber, p. 13.
[8] The Block 1 rate premium varies by voltage sub-class based on the proposed loss factors.
[9] Direct Testimony of Justin Bieber, pp. 13-14.
[10] Direct Testimony of Justin Bieber, p. 14.

Kroger's proposed rate design improves the alignment between the demand and energy charges and costs by increasing the differential between the LGS Block 1 rate and Block 2 rates to be more consistent with the differential between the GS Block 1 and Block 2 energy rates. Kroger's recommended change does not move LGS rate design 100% to cost-based rates, but it makes a step in the right direction towards improving the alignment between the charges and underlying costs for the LGS rate schedule. In fact, Kroger's recommended rate design would only recover 65% of demand related costs through demand-related charges while still recovering over 340% of energy-related costs through energy-related revenues. This is an intentional component of the proposal that mitigates the intra-class rate impacts that may result from a more significant movement towards cost at this time.[11] The alignment between charges and costs for Kroger's recommended rate design and a comparison to I&M's proposed rate design is shown in the Table below.[12]

I&M and Kroger Proposed Charges Relative to Costs
For the LGS Rate Schedule at I&M's Proposed Revenue Requirement

Classification	I&M Charges/Costs	Kroger Charges/Costs
Demand	49.6%	64.5%
Energy	443.5%	341.6%
Customer	105.5%	105.5%

Mr. Nollenberger stated in his Rebuttal Testimony that while he continues to support his proposed LGS rate design he does not believe that Mr. Bieber's proposed LGS rate design (as described above) is unreasonable. Mr. Nollenberger stated:

> "*First, it is important to note that I maintain support of I&M's proposed LGS rate design. However, while I do not agree with each of Mr. Bieber's concepts and assumptions, I do not find the rates proposed by Kroger in this Cause to be unreasonable.*"[13]

In order to provide sufficient information so that the Commission and I&M can be comfortable with Kroger's proposal, Mr. Bieber prepared a rate impact analysis that illustrates the total bill impacts to customers that would result from his recommended LGS rate design at I&M's proposed revenue requirement. The bill impacts range between 6.6% for higher load factor customers to 15.4% for lower load factor customers, at I&M's proposed

[11] Direct Testimony of Justin Bieber, p.14.
[12] Direct Testimony of Justin Bieber, p. 15.
[13] Rebuttal Testimony of Mathew Nollenberger, p. 17.

12.1% overall increase for the LGS class.[14] Obviously, if the Commission approves a lesser revenue requirement than proposed by I&M the rate impacts to LGS high- and low- load factor customers will proportionately decrease.[15]

As explained above, I&M's proposed rate design contains a significant misalignment between the costs and charges based on its own cost of service study, which results in a considerable intra-class subsidy from higher-load-factor customers to lower-load-factor customers. By gradually reducing this intra-class subsidy, lower-load-factor customers will experience slightly greater rate increases than higher-load-factor customers. This is a reasonable result because it strikes a balance between two important rate-making principles – improving the alignment between rates and the underlying cost components while employing gradualism. Kroger respectfully requests that the Commission approve this step toward reducing the subsidy paid by higher-load factor LGS customers to lower load factor LGS customers.

Kroger's Proposed Order with respect to the LGS rate design is below. In drafting its Proposed Order Kroger consulted with Walmart, which like Kroger, proposes that interclass subsidies in LGS rates be gradually reduced in this case. Kroger and Walmart submit their proposed orders on the LGS Tariff as joint proposal:

PROPOSED ORDER

<u>Tariff LGS</u> (Corresponds with pages 69-70 of I&M's Proposed Order)

(a) <u>Intervenors.</u> Kroger witness Bieber explained that I&M's own cost of service study establishes that I&M's proposed LGS rate design significantly understates demand-related charges while overstating energy charges relative to the underlying cost components. Bieber Direct, 4. In order to address this misalignment of costs and rates within the LGS class, Kroger recommended a rate design that would increase demand-related charges to 65% of the demand-related costs while reducing the energy charges by a corresponding amount to recover I&M's total proposed LGS revenues. Mr. Bieber proposed that the Company maintain the proposed demand charges for Tariff LGS and increase the differential between the LGS-Secondary Block 1 rate and Block 2 rates so that is equal to the differential between the GS-Secondary Block 1 and Block 2 energy rates. The Tariff LGS Block 1 and Block 2 rates for the other voltage subclasses should incorporate the loss factor adjustments as proposed by the Company. Bieber Direct, 13-14.

[14] See Direct Testimony of Justin Bieber, Exhibit JDB-2.

[15] To the extent that the Commission approves a revenue target for the LGS rate schedule that is different than I&M is seeking, Mr. Bieber recommended that the differential between the LGS Block 1 and Block 2 rates be maintained equal to the differential between the GS Block 1 and Block 2 rates. This would require equal reductions to both the Block 1 and Block 2 rates by the amount necessary to recover the approved revenue target for the LGS rate schedule. Adjusting the rate design in this manner would ensure that the bill impacts for all LGS customers would be reduced relative to I&M's filing and it would maintain certain rate relationships with the GS rate schedule. Alternatively, each rate element in Mr. Bieber's proposed LGS rate design can be reduced by an equal percentage in order to recover the target revenue requirement.

Walmart witness Chriss generally agreed with the position set forth by Kroger, and presented evidence that the Company's hours-use Tariff LGS, particularly for the LGS-Secondary customer class, incorporates rates that improperly collect demand-related charges through the energy charge component of the rate. Chriss, 21-29. According to Mr. Chriss, the Company's proposed rate design for Tariff LGS is inconsistent with the Company's own statements that rate components should "reflect the underlying costs of the Company" which includes "collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical." *Id.* at 19 (quoting Nollenberger, 9). Mr. Chriss recommended that at the Company's requested revenue level: 1) any approved revenue increase to the LGS class should be applied to each service level's demand charge; 2) the Company should maintain the first block energy charges at current levels; and 3) the Company should reduce the second block energy charges as proposed by I&M and increase the demand charge to account for the reduced second block energy charge revenues. Chriss at 21-30. In the event that the Commission approves a lower revenue increase than the Company has requested, Mr. Chriss recommended that the Commission should apply Walmart's proposal but then reflect the reduced revenue increase in the first block energy charges. *Id.* at 31.

(b) Rebuttal. Mr. Nollenberger disagreed with Mr. Bieber and Mr. Chriss that recovering demand-related costs through energy charges results in subsidies paid by high load factor customers to lower load factor customers within a given class. Nollenberger Rebuttal, 15-16; Attachment MWN-R1. He did not find the rates proposed by Kroger or rate design methodology presented by Walmart to be unreasonable but continued to support I&M's

(c) Discussion and Finding. The record shows Walmart's and Kroger's proposed rate designs improve the alignment between demand and energy charges and the Company's cost of service study, which results in rates that are more closely aligned with the underlying cost components and that send more efficient price signals to customers Chriss, 21-28, 31-32; Bieber, 9-15. For these reasons, and also considering that I&M has found Walmart's and Kroger's proposals to be "not unreasonable," we find that the principle underlying Walmart's and Kroger's proposed Tariff LGS-Secondary rate design is reasonable and therefore is approved. Specifically, we find that the Company should maintain the proposed demand charges for Tariff LGS and increase the differential between the LGS-Secondary Block 1 rate and Block 2 rates so that is equal to the differential between the GS-Secondary Block 1 and Block 2 energy rates. The Tariff LGS Block 1 and Block 2 rates for the other voltage subclasses should incorporate the loss factor adjustments as proposed by the Company. Bieber Direct, 13-14.

II. COST OF SERVICE

A. The Commission Should Reject The Production Cost of Service Allocation Methodologies Proposed By The OUCC.

In his Direct Testimony, OUCC witness Glenn Watkins states that there is no single, correct method to allocate joint generation costs and that the results of multiple, yet reasonable, methods should be considered.[16]

[16] Direct Testimony of Glenn Watkins, pp. 23-24.

According to Mr. Watkins, the single coincident peak, four coincident peak, and 6 CP cost allocation methods do not reasonably reflect cost causation for electric utilities because those methods do not properly consider the type of generation investments.[17] He asserts that the BIP, Probability of Dispatch, and P&A methods better reflect the capacity/energy tradeoffs. However, due to the forecasted test year in this case and the significant data required for the Probability of Dispatch method, he states that the Probability of Dispatch method is not appropriate in this case. Therefore, Mr. Watkins performed three alternative Class Cost of Service Studies ("CCOSS") using the Peak and Average ("P&A"), Base Intermediate Peak ("BIP"), and twelve-coincident peak ("12 CP") methods to allocate production plant costs.[18]

As explained below, Kroger disagrees with Mr. Watkins analysis concerning production costs allocation. The P&A allocation method utilized by Mr. Watkins in his alternative CCOSS is inappropriate in this case due to an inherent conceptual flaw that contributes to a bias against higher-load-factor customer classes. Further, the BIP and 12 CP methods for allocating costs are not consistent with Indiana & Michigan Power Company's ("I&M" or the "Company") capacity obligations as determined by PJM.

1. The P&A Method.

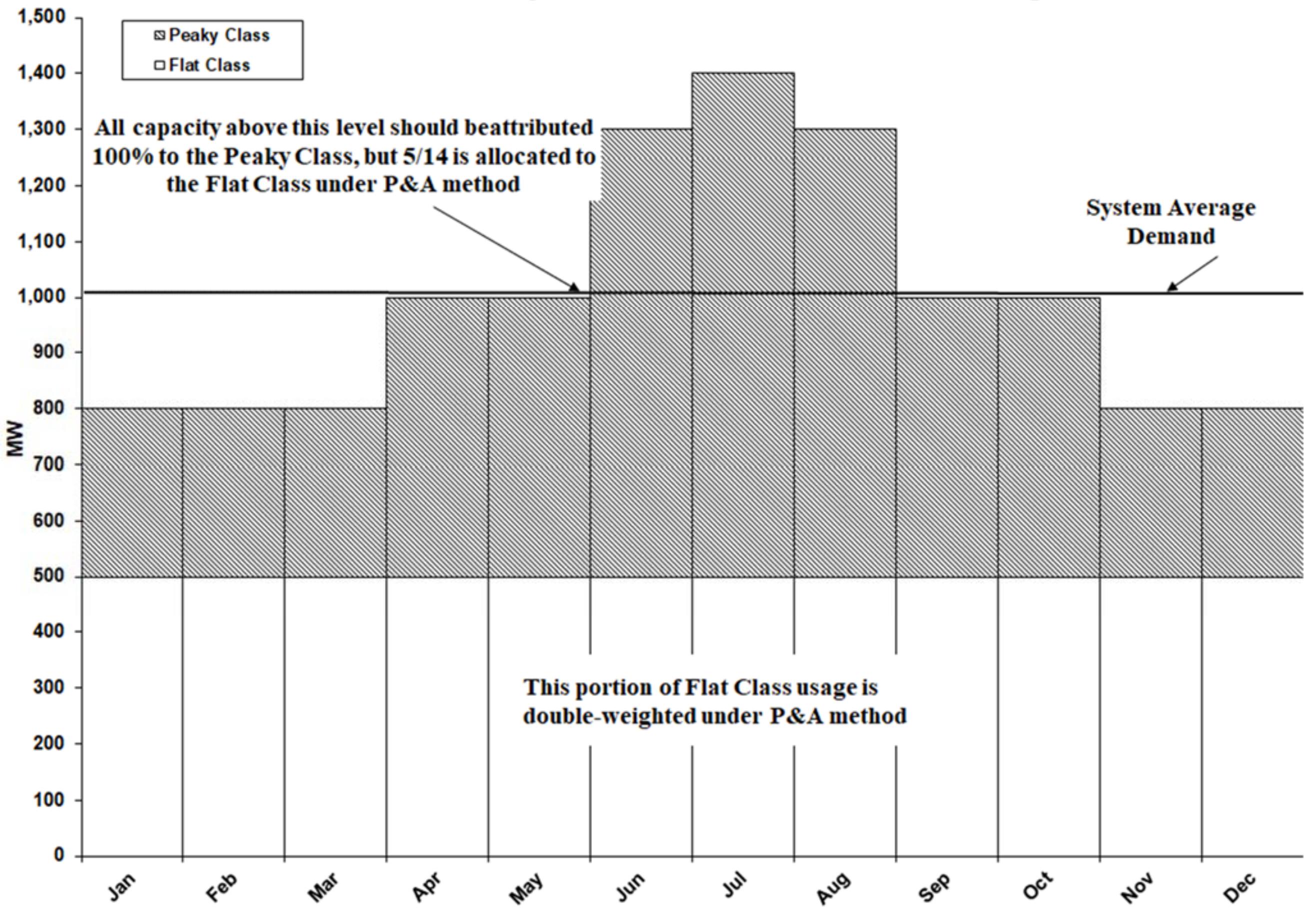
As Mr. Bieber explained in his Cross-Answer Testimony,[19] the P&A methodology has an inherent analytical flaw that results in a double energy weighting. This method incorporates a subjective determination that includes the full value of average demand (the energy divided by hours in the year) in both the "average" component *and* the peak component of the calculation. As a result, the method "double-weights" the energy component and does not properly assign the cost of production plant. This structural bias unreasonably disadvantages higher-load factor customers.[20]

According to the P&A method, fixed production cost is allocated based on a combination of each class's share of energy usage, as well as each class's share of coincident peak demand. As explained by Mr. Bieber, we can use a simple example to illustrate the P&A method and its inherent analytical flaw.[21] Assume we have two

[17] Id, p. 14.
[18] Id, p. 24.
[19] See Cross-Answer Testimony of Justin Bieber, pp. 3-6.
[20] Cross-Answer Testimony of Justin Bieber, p. 3.
[21] Cross-Answer Testimony of Justin Bieber, pp. 4-5.

customer classes: Flat and Peaky. To highlight the underlying drivers of the P&A method, let us assume that the Flat class has a constant load of 500 MW throughout the year. Let us further assume that the load pattern of the Peaky class is as follows: January-March: 300 MW; April-May: 500 MW; June: 800 MW; July: 900 MW; August: 800 MW; September-October: 500 MW; and November-December: 300 MW. This example is illustrated in the Figure below (presented as Figure JDB-1 on page 5 of Mr. Bieber's Cross-Answer Testimony):

Peak and Average Allocation Method: Illustrative Example



The Figure above shows the monthly demand of the Flat class at the bottom of the diagram. The monthly demand of the Peaky class is stacked on top of the Flat class's demand, such that the sum of the two constitutes the total demand for the system. The average demand of each of these classes is 500 MW, resulting in an average demand for this two-class system of 1000 MW. Accordingly, the P&A method will allocate each of these classes 50 percent of the responsibility for the energy, or average demand, portion of costs.[22]

[22] Cross-Answer Testimony of Justin Bieber p. 5.

The system peak demand of 1400 MW occurs in July. It is clear in this example that all of the incremental capacity required above the system average of 1000 MW demand is caused by the needs of the Peaky class – after all, the load of the Flat class is, of course, flat. But the P&A method will *not* allocate the full cost of this incremental capacity to the Peaky class. Instead, it will allocate these incremental costs in accordance with each class's share of demand during the peak month of July; that is, the Flat class will be allocated 5/14 of the incremental cost and the Peaky class will be allocated 9/14 of the incremental cost. Put another way, even though all of the Flat class's usage during July *has already been accounted for* in the allocation of average demand, the Flat class will be allocated an *additional* 5/14 of the costs of the incremental capacity above system average demand when the July peak demand is apportioned. This additional allocation occurs because the P&A method allocates capacity costs based on total demand during July, which includes the average demand *and* the excess demand. Since the average demand has already been fully allocated in the first step, this additional allocation results in a double-weighting of the average demand. This double-weighting is an inherent analytical flaw that inappropriately biases the P&A method.[23]

Mr. Bieber's rejection of the P&A method is supported by The National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual") which classifies the P&A method as a "Judgmental Energy Weighting"[24] approach and notes that shifting costs to higher-load factor customers in this manner is a matter of subjective judgment. Due to this analytical flaw Kroger recommends that the Commission reject the use of the P&A method to allocate production costs in this case.

2. 12 CP Method

I&M operates as a Load Serving Entity ("LSE") within PJM. Both I&M and PJM are summer peaking systems.[25] The PJM Peak Load Contributions ("PLC") for I&M and the LSE's included in its load obligation drive I&M's capacity needs.[26] As explained by Mr. Bieber, if any changes are made to I&M's proposed 6 CP method for allocating production costs, then it would be appropriate to shift towards a production allocator that is focused on using fewer than six peaks to reflect the nature of I&M's summer peaking loads. A 12 CP production cost

[23] Cross-Answer Testimony of Justin Bieber, p. 6.
[24] NARUC Manual at 57 (1992).
[25] I&M Response to Data Request No. CAC 3-06 a) ii), reproduced in Exhibit JDB-1R.
[26] I&M Response to Data Request No. IG 2-10, reproduced in Exhibit JDB-1R.

allocator includes monthly peak loads that do not coincide with either the I&M system peaks or the PJM system peaks. Therefore, utilizing the 12 CP method in this case would constitute movement in the wrong direction with respect to cost causation given the summer peak loads that drive I&M's capacity requirements.[27]

3. The BIP Method.

Similar to the P&A cost allocation methodology, the BIP allocation method is another method which is classified as a "judgmental energy weighting" by the NARUC Manual.[28] Given the PJM summer system peaks that drive I&M's capacity requirements, the 6 CP is more aligned with cost causation than the BIP method in this case.[29]

B. The Commission Should Reject CAC's and INCAA's Recommendation Regarding The Allocation Of Production Costs.

CAC and INCAA witness Jonathan Wallach asserts that the Company's CCOSS inappropriately classifies all production plant costs as demand-related because under typical generation expansion planning practices, plant investment choices are driven by both reliability and energy requirements.[30] Mr. Wallach recommends using the Equivalent Peaker classification method to allocate production costs because it classifies production costs in a manner that reasonably reflects investment decision-making according to typical generation planning practices.[31]

Mr. Wallach estimated the demand and energy portions of I&M's production portfolio based on the Company's generation plant and the cost and capacity of gas turbines installed in Indiana and Michigan. Mr. Wallach relied on gas-turbine data from other utilities because I&M does not own any gas turbines. To determine the demand-related portion of I&M's production plant, Mr. Wallach multiplied I&M's total plant capacity by the cost per kW of plant capacity for gas turbines installed in Indiana and Michigan between 1967 and 2002. Using this approach, Mr. Wallach proposes a modified CCOSS based on his estimate that 31% of I&M's production costs are demand-related and 69% are energy-related.[32]

[27] Cross-Answer Testimony of Justin Bieber, pp. 6-7.
[28] NARUC Manual at 60 (1992).
[29] Cross-Answer Testimony of Justin Bieber, p. 7.
[30] Direct Testimony of Jonathan Wallach, p. 12.
[31] Id, p. 14.
[32] Direct Testimony of Jonathan Wallach, pp. 14-15.

Mr. Wallach's modified CCOSS which allocates production plant costs using the Equivalent Peaker method is not appropriate because, according to the NARUC Manual, the premise of the Equivalent Peaker method assumes that increases in peak demand require the addition of peaking capacity only; and that utilities incur the costs for more expensive intermediate and baseload units because of the additional energy loads they must serve.[33]

It is important to understand the historical context during the time that these units were being planned and built. The Powerplant and Industrial Fuel Use Act ("FUA") was passed in 1978 due to national energy security concerns stemming from the 1973 oil crisis and the natural gas curtailments of the mid-1970s. The FUA restricted the construction of power plants using oil or natural gas as a primary fuel and encouraged the use of coal, nuclear, and other alternative fuels.[34] Although the FUA allowed an exception for peaking plants, that exception was only permitted through petition to the Secretary of Energy.[35] In 1987, the FUA was repealed and these restrictions were eliminated.[36]

I&M's Rockport coal power plant and Cook nuclear power plant constitute over 97% of I&M's gross production plant in service for the 2020 test year.[37] The first Rockport coal unit was placed in service in 1984, while the first Cook nuclear unit was placed in service in 1975.[38] These power plants were planned during a time when there were natural gas curtailments and the construction of natural gas power plants was restricted. During this time, electric utilities could not just as easily install natural gas fueled combustion turbines as other technologies.[39] Thus, the premise underlying the Equivalent Peaker method that utilities would only incur costs for more expensive units because of additional energy loads is *not* consistent with the historical generation planning practices during the timeframe when the overwhelming majority of I&M's production plant was being planned.[40] Kroger recommends against a change to the Equivalent Peaker allocation methodology as it is not appropriate to

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[33] NARUC Manual at 53 (1992).
[34] Repeal of the Powerplant and Industrial Fuel Use Act (1987), U.S. Energy Information Administration, https://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html.
[35] Power Plant and Industrial Fuel Use Act, U.S. Department of Energy, https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/other-regulatory-efforts/power-plant.
[36] Repeal of the Powerplant and Industrial Fuel Use Act (1987), U.S. Energy Information Administration, https://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html.
[37] Id, Attachment JFW-7.
[38] S&P Global Market Intelligence, Power Plant Briefing Book.
[39] Cross-Answer Testimony of Justin Bieber, p. 9.
[40] Cross-Answer Testimony of Justin Bieber, pp. 9-10.

apply this methodology in this case to the Rockport and Cook generation facilities which were planned and constructed prior to the repeal of the FUA in 1987.

PROPOSED ORDER

Kroger does not propose changes to I&M's Proposed Order with regard to the Class Cost Of Service Study.

III. REVENUE REQUIREMENT AND RIDERS

A. I&M's Proposals With Respect To Off-System Sales Margin Sharing ("OSS") And PJM Cost Rider, Resource Adequacy Rider ("RAR"), And Advanced Metering Infrastructure ("AMI") Rider Are Examples Of Single-Issue Ratemaking And Should Be Rejected.

Single-issue ratemaking occurs when utility rates are adjusted in response to a change in a single cost or revenue item considered in isolation. It ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change. Setting rates based on a single cost or revenue item runs contrary to the basic principles of traditional utility regulation. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. Alternatively, a single revenue item considered in isolation might cause a decrease in rates without recognizing counterbalancing cost increases in other areas. For these reasons, single-issue ratemaking, *absent a compelling public interest*, is generally not sound regulatory practice.[41]

In its 2014 Annual Report, the Commission indicated its position that expense trackers can be reasonable if *all* of these criteria are met:[42]

1) The anticipated costs or revenues are volatile in nature;
2) The anticipated costs or revenues are largely outside the utility's control; and
3) The anticipated costs or revenues are materially significant costs or revenues.

[41] Direct Testimony of Justin Bieber, pp. 17-18.
[42] Indiana Utility Regulatory Commission 2014 Annual Report, p. 39. "An expense tracker allows retail rates to be adjusted outside the context of a base rate case to reflect changes in operating expenses. These adjustments do not include the recovery of any financing cost, but merely allow the utility to recover what it has spent on a dollar-for-dollar basis. The pass-through of unpredictable revenues and expenses to ratepayers reduces volatility in the utility's earnings which serves to strengthen the utility's credit rating. *Recovery of expenses that are characterized as largely outside the utility's control, volatile in nature, and materially significant is the intended goal of such trackers* [emphasis added]."

The Commission should reject the Company's proposals to expand its tracker cost recovery under the OSS/PJM Rider, RAR, and AMI riders. The proposed expansions for these tracker recovery mechanisms amount to single-issue ratemaking that do not address a compelling public interest or meet the generally accepted criteria for this type of regulatory treatment. I&M's proposals would expand its cost recovery under these single-issue trackers without consideration of whether the Company would experience offsetting decreases in expenses or increases in revenues. Further, it would reduce the inherent incentive for the Company to reduce costs beyond what is necessary to be deemed prudent in a rider reconciliation proceeding.[43]

1. OSS/PJM Cost Rider.

The OSS/PJM rider is currently is used to track the net PJM costs that result from I&M's role as a Transmission Owner, Generation owner, and Load-Serving Entity in addition to tracking I&M's OSS margins. Currently, 100% of PJM Network Integration Transmission Service ("NITS") charges are recovered through the rider with no costs embedded in base rates. All other PJM charges, or non-NITS charges, are embedded in base rates and tracked above and below the amount embedded in rates. The cost recovery of certain PJM NITS charges is capped and the tracking of PJM costs through the OSS/PJM rider currently sunsets on the earlier of the date that new rates from this base rate case go into effect, or December 31, 2021. The rider also tracks all OSS margins above $0 and shares the margins so that 95% flows to customers and 5% goes to the Company.[44]

I&M witness Andrew Williamson explained that I&M is proposing to remove the sunset provision on the tracking of PJM costs and to remove the cap on certain PJM NITS charges. I&M is also proposing to begin tracking the costs of PJM Capacity Performance insurance.[45] According to Mr. Williams, it is reasonable to fully track I&M's PJM NITS costs because they are significant, variable, and largely outside the utility's control.[46]

Kroger recommends that the Commission reject I&M's proposal to remove the sunset provision and continue fully tracking PJM costs. Instead I&M's reasonable PJM costs for the test year should be embedded in base rates with no incremental tracker recovery through the OSS/PJM rider. I&M's proposal does not meet the

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[43] Direct Testimony of Justin Bieber, p. 5.
[44] Direct Testimony of Andrew J. Williamson, pp. 48-49.
[45] Id, p. 49.
[46] Id, p. 52.

generally accepted criteria for cost trackers because the costs are not volatile. Mr. Williamson asserts that the PJM costs are variable because they are expected to increase in the future. This argument confuses the concepts of variability and volatility. While the PJM costs may be projected to increase beyond the Test Year, I&M, AEP, and PJM have a robust transmission planning process to identify and plan long term transmission investments. As such, the PJM costs resulting from transmission investments are not subject to significant or unknown volatility.[47]

This lack of volatility is evident from I&M's own testimony. According to I&M witness Kamran Ali, I&M's forecast of its PJM costs is expected to increase consistently from the Test Year through at least 2023.[48] I&M's request to track these PJM costs provides a classic example of cost tracking that is not in the public interest. I&M's proposal would allow it to track predictably increasing costs in one specific area while avoiding a base rate case that would consider all of the other offsetting revenues and expenses. This approach ignores the potential for decreasing costs in other areas to offset this expected increase.[49]

Further, according to Mr. Ali, PJM NITS charges in the AEP Zone are derived from the transmission investments of all TOs in the AEP Zone.[50] Since all of the Transmission Owners in the AEP zone are AEP affiliates,[51] a large proportion of the PJM NITS costs are under the control of I&M and its AEP affiliates. Allowing these costs to be recovered through a single-issue tracker diminishes the incentive for I&M and its affiliates to reduce costs below the level that is necessary in order to be deemed prudent in a rider reconciliation proceeding.[52]

PROPOSED ORDER

Off-System Sales Margin Sharing. (Corresponds with pages 77-78 of I&M's Proposed Order)

Discussion and Finding. The proposed expansion of the OSS margin sharing mechanism is denied as it amounts to single-issue ratemaking that does not address a compelling public interest or meet the generally accepted criteria for this type of regulatory treatment. I&M's proposal would expand its cost recovery under this single-issue tracker without consideration of whether the Company would experience offsetting decreases in expenses or increases in revenues. Further, it would reduce the inherent incentive for the Company to reduce costs beyond what is necessary to be deemed prudent in a rider reconciliation proceeding.

[47] Direct Testimony of Justin Bieber, pp. 20-21.
[48] Direct Testimony of Kamran Ali, p. 17.
[49] Direct Testimony of Justin Bieber, p. 21.
[50] Direct Testimony of Kamran Ali, p. 9.
[51] I&M Response to Data Request No. Kroger 4-02, reproduced in Exhibit JDB-3.
[52] Direct Testimony of Justin Bieber, p. 21.

2. Resource Adequacy Rider (RAR)

The RAR currently tracks the incremental non-fuel purchased power costs that I&M incurs for its Unit Power Agreement with AEP Generating Company for a portion of the Rockport Plant and the Inter-Company Power Agreement with Ohio Valley Electric Corporation that are above or below the level embedded in rates.[53] Similar to the OSS/PJM rider, the RAR has a cap on costs and will sunset on the earlier of December 31, 2021 or the date rates go into effect for this rate case.[54]

I&M is proposing to eliminate the cost cap and sunset provisions for this rider so that it can continue to track incremental non-fuel purchased power costs and is also proposing to update the level of non-fuel purchased power embedded in base rates for the test year to $190.1 million.[55] Similar to I&M's proposal to expand tracker revenue recovery through the OSS/PJM rider, I&M's proposal to eliminate the sunset provision for the RAR amounts to single-issue ratemaking and should be denied. Instead, I&M's reasonable non-fuel purchased power costs for the Test Year should be embedded in base rates with no incremental tracker recovery through the RAR. The costs for I&M's non-fuel purchased power contracts are predictable long-term costs and don't meet the generally accepted criteria for cost trackers because the costs are not volatile.[56]

This is another example of I&M proposing a single cost category for tracker recovery while ignoring the potential for offsetting costs and revenues in other areas. Further, expanding this single-issue rider would provide tracking for costs paid to I&M affiliates and diminish the incentive for I&M and its affiliates to reduce these costs as much as possible.[57]

PROPOSED ORDER

Resource Adequacy Rider. (Corresponds with pages 82-83 of I&M's Proposed Order)

Discussion and Finding. The proposed expansion of the RAR is denied as it amounts to single-issue ratemaking that does not address a compelling public interest or meet the generally accepted criteria for this type of regulatory treatment. I&M's proposal would expand its cost recovery under this single-issue tracker without consideration of whether the Company would experience offsetting decreases in expenses or increases in revenues. Further, it would reduce the inherent incentive for the Company to reduce costs beyond what is necessary to be deemed prudent in a rider reconciliation proceeding.

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[53] Direct Testimony of Andrew J. Williamson, p. 54.
[54] Cause No. 44967, Final Order, May 30, 2018, pg. 13.
[55] Direct Testimony of Andrew J. Williamson, pp. 54-55.
[56] Direct Testimony of Justin Bieber, p. 22.
[57] Direct Testimony of Justin Bieber, pp. 22-23.

3. Advanced Metering Infrastructure (AMI) Rider

I&M is proposing to track the full costs associated with its AMI deployment through a new AMI rider until those costs are reflected in base rates.[58] According to Mr. Williamson, the AMI deployment will result in significant costs in a relatively short time period following the Test Year and it would be inefficient and ineffective to require I&M to file another general rate case immediately following this proceeding to address a majority of the costs for the AMI deployment.[59]

The Commission should deny I&M's request to expand its recovery through a new AMI tracking mechanism. Instead, a reasonable level of AMI related costs for the Test Year should be embedded in base rates with no incremental tracking of costs. I&M's proposal for a new AMI rider fails to meet two of the generally accepted criteria for single issue trackers because the costs are reasonably controllable by management and the costs are not volatile. Further, I&M is already proposing to utilize a future Test Year in this case which substantially mitigates challenges that can occur due to regulatory lag. There is not a compelling public interest for I&M's request to further expand its single-issue cost tracking with a new tracking mechanism to recover AMI deployment costs.[60]

PROPOSED ORDER

AMI Rider. (Corresponds with pages 73-74 of I&M's Proposed Order)

Discussion and Finding. I&M's request to expand its recovery through a new AMI tracking mechanism is denied. I&M's proposal for a new AMI rider fails to meet two of the generally accepted criteria for single issue trackers because the costs are reasonably controllable by management and the costs are not volatile. Further, I&M is already proposing to utilize a future Test Year in this case which substantially mitigates challenges that can occur due to regulatory lag. There is not a compelling public interest for I&M's request to further expand its single-issue cost tracking with a new tracking mechanism to recover AMI deployment costs.

B. The Commission Should Reject I&M's Proposal To Recover The Cost Of Capacity Performance Insurance.

I&M witness Toby Thomas explains that PJM's capacity performance rules monitor the reliability of PJM member's capacity resources to ensure the resources are available to serve customer requirements. These rules assess Non-Performance Charges if a generator does not meet PJM's capacity performance requirements during a

[58] Direct Testimony of Andrew J. Williamson, p. 37.
[59] Direct Testimony of Andrew J. Williamson, p. 35.
[60] Direct Testimony of Justin Bieber, p. 23.

PJM Emergency or Performance Assessment Interval ("PAI"). If any of I&M's resources are experiencing an unexpected forced outage during a PAI, I&M will incur a Non-Performance Charge. To insure against the risk of a Non-Performance Charge, I&M has purchased capacity performance insurance.[61] I&M is proposing to embed the cost of PJM capacity performance insurance in base rates and track any incremental costs through the OSS/PMJ rider. It is important to note that I&M has indicated that it is not aware of any other utilities or generator owners that recover the costs of capacity performance insurance from customers through base rates or rider tracking mechanisms.[62]

The Commission should reject I&M's proposal to recover the costs of capacity performance insurance from customers. I&M earns a rate of return on its production plant and other rate base assets that is intended to compensate for the business risks of running a utility. Maintaining a capacity resource's availability during an emergency event and in compliance with PJM's reliability requirements and capacity performance rules is a fundamental responsibility for a generation owner participating in the PJM market. Customers should not be responsible for penalties resulting from I&M's failure meet PJM's capacity performance requirements for its resources. Likewise, the additional costs of I&M's capacity performance insurance to protect the Company's shareholders against the risk Non-Performance Charges should not be passed on to customers. However, to the extent that the Commission does allow I&M to include capacity performance insurance costs in base rates, it should not allow the incremental costs of the insurance to be recovered through the OSS/PJM rider since tracking those costs would not meet the generally accepted criteria for a single-issue cost tracker.[63]

PROPOSED ORDER

PJM Rider and PJM Capacity Performance Insurance. (Corresponds with pages 78-82 of I&M's Proposed Order)

Discussion and Finding. I&M's proposal to recover the cost of capacity performance insurance is denied. I&M earns a rate of return on its production plant which is intended to provide an appropriate balance between the risks and rewards for I&M's operations. If I&M elects to purchase capacity performance insurance to mitigate its operational risk from incurring a non-performance charge for failure to meet PJM's resource requirements, that cost should not be passed on to customers.

[61] Direct Testimony of Toby L. Thomas, p. 33.
[62] I&M Response to Data Request No Kroger 2-15 and Kroger 5-03, reproduced in Exhibit JDB-3.
[63] Direct Testimony of Justin Bieber, pp. 25-26.

C. I&M's Proposal To Embed Zero OSS Margins In Base Rates And Share OSS Margins On A 95/5 Percent Basis Fails To Properly Recognize Customer Contributions That Enable I&M To Conduct OSS Trading.

I&M proposes to continue tracking all OSS margins from $0, with customers receiving 95% of the margins, and the Company receiving 5%. According to Mr. Williamson, this sharing is reasonable because it provides an incentive for the Company to maximize OSS margins and recognizes the value of I&M's Commercial Operations organization. Additionally, Mr. Williamson explains that OSS incentives are even more important as IMMDA contracts expire and there are additional opportunities for OSS margins. Lastly, he asserts that it is reasonable to track OSS margins from $0 rather than embed a certain level in base rates because OSS margins are contingent on PJM market prices, are variable from year to year, and dependent on factors outside the Company's control.[64]

To the extent that the Company is receiving a share of the OSS margins, Kroger recommends that the Commission order I&M to embed a reasonable level of OSS margins in base rates. I&M forecasts the annual OSS margins to increase from $7.3 million in 2017-2018 to $38.4 million in the Test Year, driven in part by new opportunities for OSS resulting from the expiration of the IMMDA wholesale contracts.[65] Sharing OSS margins from $0 without any OSS margin in base rates would provide an asymmetrical upside margin sharing potential for I&M's shareholders without any commensurate risk. This proposal fails to recognize the contribution that ratepayers have made towards the plant and personnel expenses that provide I&M the opportunity to conduct OSS trading. While it may be reasonable to provide I&M an incentive to maximize OSS margins, it is not reasonable to provide a margin sharing incentive from a zero-baseline level without requiring I&M to take some responsibility and commensurate risk to achieve a reasonable level of OSS margins.[66]

Given the facts of this case, including the significant increase in forecasted OSS margins from recent years, Kroger recommends that I&M embed its $38.4 million forecasted level of OSS margins in base rates, and track the incremental OSS margins above or below this level with 95% going to customers and 5% to the Company.

[64] Direct Testimony of Andrew J. Williamson, pp. 49-50.
[65] Id, p. 50.
[66] Direct Testimony of Justin Bieber, p.27.

However, to the extent that the Commission approves I&M's proposal to embed $0 of OSS margin in base rates, then Kroger recommends that customers should receive 100% of the OSS margins.[67]

PROPOSED ORDER

Off-System Sales Margin Sharing (Corresponds with pages 77-78 of I&M's Proposed Order)

Discussion and Finding. I&M's proposal to embed zero OSS margins in base rates and share OSS margins with 95% going to customers and 5% going to the Company fails to properly recognize the contribution customers have made to the capital and operating costs that enable I&M to conduct OSS trading. The Commission finds that I&M should include its $38.4 million forecasted amount of OSS margins in base rates and approves I&M's proposed 95/5 sharing of the incremental OSS margins above or below that amount.

Respectfully submitted,

/s/ Kurt J. Boehm

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ATTORNEYS FOR THE KROGER CO.

December 3, 2019

[67] Direct Testimony of Justin Bieber, p. 27.

CERTIFICATE OF SERVICE

I hereby certify that true copy of the EXCEPTIONS AND PROPOSED ORDER OF THE KROGER CO. was served by electronic mail (when available) or regular U.S. mail, postage prepaid (unless otherwise noted), this 3rd day of December, 2019, to the parties listed below.

/s/ Kurt J. Boehm
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