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Cause No. 45235

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

MATTHEW W. NOLLENBERGER

INDEX

PRE-FILED VERIFIED DIRECT TESTIMONY OF MATTHEW W. NOLLENBERGER ON BEHALF OF INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is Matthew W. Nollenberger, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and what is your position?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Manager, Regulated Pricing and Analysis. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power (AEP) system, one of which is Indiana Michigan Power Company (I&M or the Company).

Q. Please describe your educational and professional background.

A. I graduated from Bowling Green State University in 1989 with a Bachelor of Science degree in Technology, with a major in Construction Technology. From 1990 to 1996 I was employed as a Project Engineer in the construction services industry. In 1998, I earned a Master of Business Administration degree from the Ohio State University.

In 1998, I joined AEPSC as an Energy Associate in its Energy Trading and Marketing organization. In 2000, I transitioned from Energy Associate to Energy Trader. In 2002, I joined AEP's Fundamental Analysis organization where I supported the Trading and Marketing organization by providing various power and fuel market fundamental analyses. In 2005, I was promoted to Manager, Marketing Administration, where I managed AEP's wholesale power marketing contract administration process. In 2008, I joined AEP's RTO Operations department as

Manager, Market Operations, where I represented AEP in the MISO and PJM RTO stakeholder processes.

In 2010, I joined AEPSC's Regulatory Services as Manager, Regulatory Support, supporting AEP's Commercial Operations organization. In May of 2011, I was promoted to my current position of Manager, Regulated Pricing and Analysis. In 2013, I completed the EEI Advanced Electric Rate Course.

Q. What are your responsibilities as Manager, Regulated Pricing and Analysis?

A. My responsibilities include the oversight and the preparation of cost of service and rate design analyses for the AEP System operating companies, and the oversight and preparation of special contracts and pricing for customers.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I submitted testimony on behalf of I&M before the Indiana Utility Regulatory Commission (IURC or Commission) and the Michigan Public Service Commission. With respect to the IURC, I submitted testimony in a number of Causes, including Cause No. 44967 supporting I&M’s request for authority to increase its basic rates.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe and support the following:

- Adjustments to the jurisdictional separation study
- The calculation of I&M’s required jurisdictional rate relief for each tariff class
- The rate design supporting I&M’s proposed tariffs, including:
    - i. Residential class energy and monthly service charges
    - ii. An optional residential class demand-metered tariff

iii. The introduction of demand charges for select end-use tariff classes

iv. The Company's rider factor calculations

- The rate design and factors for the Company's proposed Phase-in Rate Adjustment
- A billing comparison of rates

Q. Are you sponsoring any attachments in this proceeding?

A. I am sponsoring the following Attachments:

- Attachment MWN-1: Transmission Cost and Revenue Adjustment
- Attachment MWN-2: Proposed Customer Class Revenue Allocation
- Attachment MWN-3: Comparison of Indiana REMC Residential Fixed Charges
- Attachment MWN-4: Typical Electric Bill Comparison

Q. Are you sponsoring any workpapers in this proceeding?

A. I am sponsoring the following workpapers:

- WP-MWN-1: Adjustment Operating Revenue No. 2 Calculation
- WP-MWN-2: Adjustment O&M No. 8 Calculation
- WP-MWN-3: Calculation of Proposed Tariff Class Revenue Requirements
- WP-MWN-4: Proposed Basic Rate Tariff Rate Design
- WP-MWN-5: Current Rider Rate Design
- WP-MWN-6: Proposed Rider Rate Design
- WP-MWN-7: Proposed Phase-In Rate Adjustment Factor Rate Design
- WP-MWN-8: Proposed Class Coincident Peak Per kWh Ratios

Q. Were the attachments and work papers that you support prepared by you or under your direction?

A. Yes.

JURISDICTIONAL ADJUSTMENTS

Q. Please describe Operating Revenue Adjustment No. 2 (OR-2) to Exhibit A-5.

A. As discussed by Company witness Williamson, the majority of I&M's wholesale contracts with the Indiana and Michigan Municipal Distributors Association ("IMMDA")[1] members will end June 1, 2020. Accordingly, I computed Adjustment OR-2 to annualize the effect of the IMMDA contract termination by removing the revenues and expenses associated with serving the IMMDA members' during the first five months of the Test Year. Adjustment OR-2 increases both energy- and capacity-related sales for resale to reflect the Company's reduction of wholesale load obligation over the same time-period. As a result of this adjustment the Company's total firm sales revenues decreased by $35,303,632 and total sales for resale revenues increased by $22,630,898. This resulted in a total Company reduction in revenues of $12,672,734. Finally, total Company energy-related purchased power expenses decreased by $457,957.

Q. Please describe O&M Adjustment No. 8 (O&M-8) to Exhibit A-5.

A. The Company's projected Test Year of calendar 2020 is a leap year comprised of 366 days. Based on the timing of the filing of this Cause, new rates are not expected to be in effect before March-April, 2020. For this reason, I adjusted the projected kWh used to develop the Company's Test Year billing determinants

[1] Members include all current IMMDA municipalities other than the cities of Garrett, IN and Dowagiac, MI.

shown in Attachment JCD-2 to reflect 365 days by removing one day of forecasted energy usage (kWh). Accordingly, Adjustment O&M-8 removes one day of Test Year fuel expense related to the one-day reduction in the Test Year billing determinants and related operating revenues. As shown in WP-MWN-2, the reduction in Test Year MWh is multiplied by the proposed fuel basing point supported by Company witness Heimberger to compute a $543,434 reduction in Indiana jurisdictional Test Year fuel expense.

Q. Please explain the ratemaking adjustment made to establish the cost of transmission service based upon PJM OATT charges instead of the embedded cost of transmission.

A. Following the same methodology established in Cause Nos. 44075 and reflected in Cause No. 44967, the Company's most recent basic rate case, I&M's entire traditional embedded cost of transmission, as well as the revenues the Company receives from PJM as a Transmission Owner, have been excluded from the Company's class cost of service study, as supported by Company witness High. As a result, these costs and revenues have been removed from the Company's revenue requirement in this proceeding, as shown on Exhibit A-1. The calculations supporting this adjustment are provided in Attachment MWN-1.

It is important to note that changes made to the Company's proposed cost of service in this proceeding may result in a change to the amount of the proposed transmission adjustment since it is based on the transmission cost of service.

REVENUE ALLOCATION

Q. What is the starting point of the rate relief allocations and rate design that you are sponsoring?

A. The tariff class rate relief allocations and rate design supporting I&M's tariffs are based on the class cost of service study performed by Company witness High for the forward-looking test period ended December 31, 2020. The Phase-In Rate Adjustment factor rate design, which I discuss later in my testimony, was computed separately based on the respective class cost of service studies also presented by witness High.

Q. Please explain the principles and objectives underlying the Company's proposed revenue allocation among the customer classes.

A. I allocated the Company's overall revenue increase among the customer classes following certain ratemaking principles to meet several objectives. First, and as an over-riding tenet, I ensured the principle of cost causation by basing the revenue allocation on the Company's proposed cost of service, as discussed above. Second, I applied the principle of gradualism when determining the individual customer class revenue increases. Third, I allocated the total revenue increase in a manner that moved all classes closer to earning the class average rate of return. Fourth, and related to the third objective, I reduced the current level of inter-class revenue subsidies. Finally, I ensured that no class received a revenue decrease based on cost of service. Each of these principles and objectives were applied in the development of the Company's proposed equal subsidy reduction method of revenue allocation.

Q. Please explain the equal percentage subsidy reduction method of revenue allocation shown on Attachment MWN-2.

A. The first step in the Company's proposed equal percentage subsidy reduction method is to calculate the current subsidy for each class. This is shown on Attachment MWN-2, Page 2, Column (12). The current subsidy is defined as the difference between the equalized revenues (revenues if the class rate of return were set equal to the total retail current rate of return of 3.41%) and current class revenues. For example, the current subsidy for the residential class is negative $7.49M, which means that residential revenues would have to be increased by that amount to raise the class rate of return to 3.41%. Conversely, the current subsidy for the General Service class (Tariff GS) is positive $8.12M, which means that Tariff GS revenues would have to be decreased by that amount to lower the class rate of return to 3.41%.

The second step is to calculate the revenues for each class at the total retail proposed rate of return. This is shown on Attachment MWN-2, Page 3, Column (11). This second step shows what each class would pay if all subsidies were eliminated and each class fully paid its actual costs at the proposed revenue level.

The third step is to exercise the principle of gradualism. The Company has chosen not to eliminate all subsidies in this Cause. However, it is important to make progress toward eliminating interclass subsidies so that customer class revenues more closely align with their respective class cost of service. The amount of such progress should be tempered by considering the rate impacts on the various tariff classes. As such, 25% of the current subsidies from all classes were eliminated. To accomplish this, 75% of the current subsidy is added back (or deducted, as appropriate) to the class rate increases (or decreases) at proposed equalized rates of return. This is shown on Attachment MWN-2, Page 3, Column (12).

The final step is simply to recalculate the results using the increase determined in the third step. This is shown on Attachment MWN-2, Page 4, Columns (6) through (10).

Q. Did you make any additional adjustments once the revenue allocation was completed?

A. Yes. Following the subsidy reduction method described above, an additional adjustment was applied to ensure that no tariff class received a decrease in total revenues (basic rates + riders). Following the initial 25% subsidy elimination process, Tariff Classes IS and SL were the only classes that received proposed revenue decreases. The resulting tariff class decreases were eliminated and allocated to all other classes on a proportion of rate base share; thus, reducing those classes' total revenue increases and ensuring that no class received a revenue decrease. These adjustments are provided in Attachment MWN-2, page 3, Column (14). Also, as shown on Attachment MWN-2, page 4, Column (11), an additional adjustment was made to include an increase of $3.9M to establish the cost of transmission service based upon PJM OATT charges instead of the embedded cost of transmission, as discussed earlier in my testimony.

RATE DESIGN

Q. Please describe the process used to develop the Company's proposed rates.

A. In general, the Company's approach is to design rates and rate components that reflect the underlying costs of the Company. This includes collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical.

The rate design process involved a number of steps that varied with each tariff. The cost components developed by Company witness High in the Test Year class cost of service study and detailed in WP-MWN-3 provided guidance as to the relative amounts of revenue that should be recovered through service charges, energy charges, and demand charges. In general, where sufficient metering data is available, full cost service charges, energy and demand rates were developed for each class by dividing the component-allocated proposed revenues by the Test Year billing units. These initial rates were then compared to the current rates to determine which price changes would need to be moderated to mitigate rate impacts that could cause individual bill impacts that might be considered too severe.

RESIDENTIAL RATE DESIGN

Q. Please describe the Company's current rate design and charges applicable to the residential customer class (Tariff RS).[2]

A. The current rate design and related charges applicable to Tariff RS consists of a simple two-part rate structure. Under this structure, all customers pay a fixed

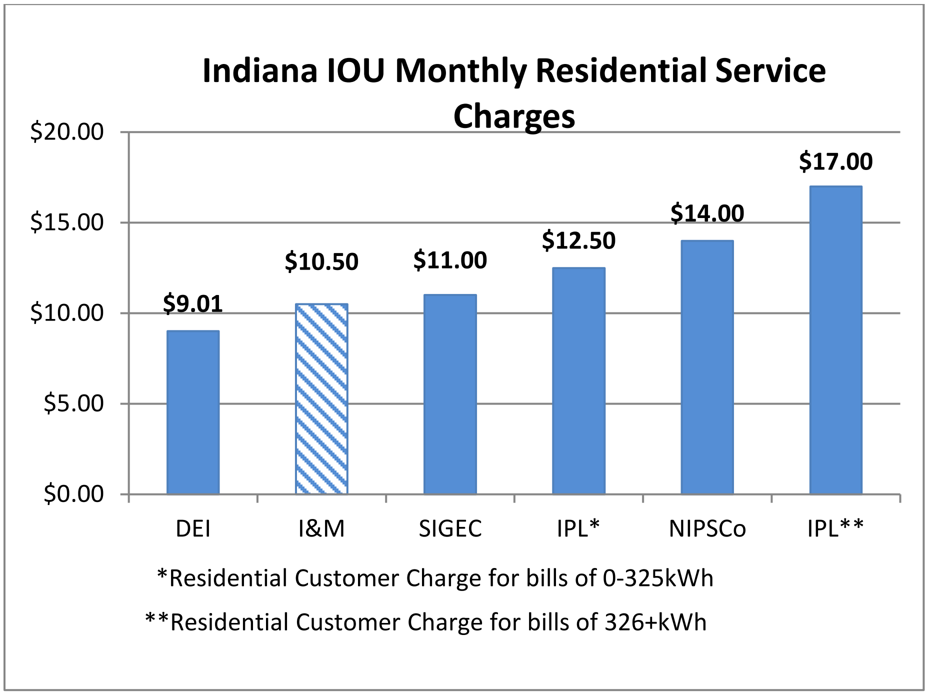
[2] For purposes of discussing I&M's proposed Residential rate design and charges, my testimony refers to the Standard Residential tariff class (Tariff RS), unless noted otherwise.

monthly service charge of $10.50 per month and a volumetric energy charge of 10.458¢ per each kWh of usage. The current monthly service charge recovers all customer-related costs, plus a small additional contribution towards fixed cost recovery. The current volumetric energy charge recovers the energy-related costs, plus the remaining fixed (demand-related) costs that are not recovered in the monthly service charge. In general, it would be preferable to recover demand-related costs through demand charges. However, the vast majority of I&M's current residential metering installations do not register customers' peak demands; therefore, a monthly demand charge is not a practicable rate component for the standard residential class.

Q. How does the Company's current Tariff RS fixed monthly service charge compare to those of other Indiana investor owned utilities (IOUs)?

A. Figure MWN-1 provides a comparison of fixed monthly service charges currently applicable to residential tariff rates among all Indiana IOUs. In addition, both Duke Energy Indiana and Indianapolis Power & Light Company include declining block volumetric energy charges in their residential tariffs as compared to I&M's flat volumetric energy charge.

Figure MWN-1



In addition, I&M's current residential monthly service charge is significantly lower than the monthly service charges paid by Indiana residential rural electric member cooperative (REMC) customers, whose median service charge is $30 and as high as $44 per month. REMC monthly fixed charges are noteworthy, given that cooperatives are customer-owned; therefore, the implemented levels and types of charges reflect what customers deem to be reasonable and appropriate. Attachment MWN-3 provides a comparison of monthly residential service charges among Indiana REMCs.[3]

While comparisons between I&M's proposed rates and those of other IOUs and REMCs provide context for the current state of residential fixed charges in

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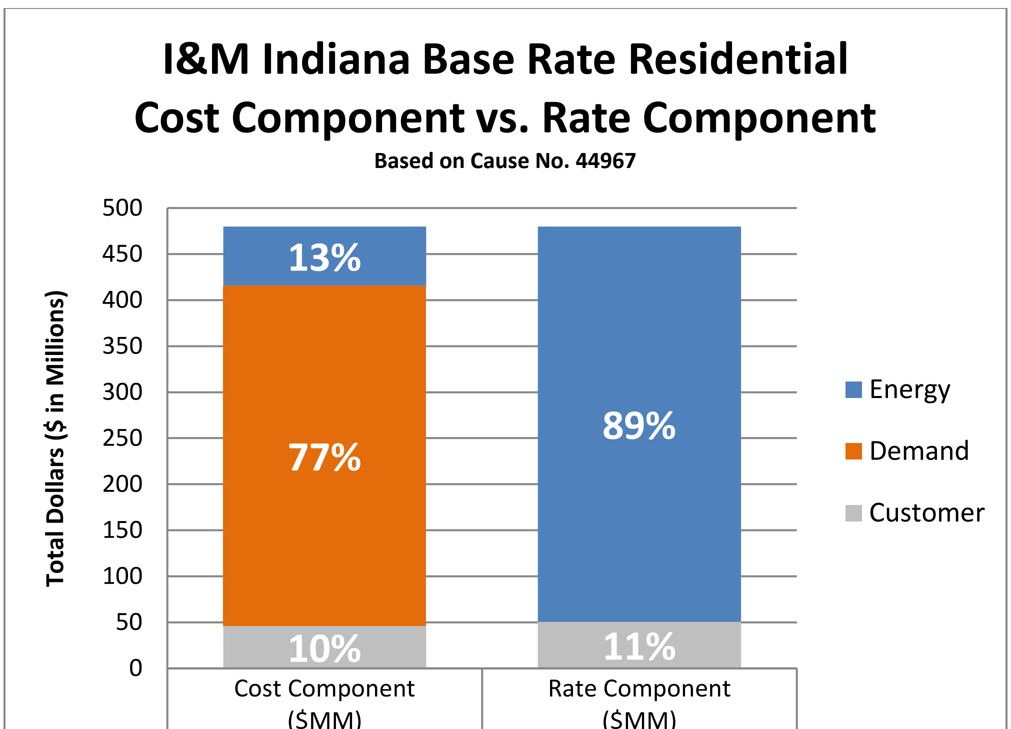
[3] The REMC charges in Attachment MWN-3 are as of April 23, 2019.

Indiana, they do not consider the potential for other IOUs and REMCs to increase their respective fixed charges over time.

Q. Please explain the Company's current costs required to serve its residential customers relative to the current rate structures designed to recover those costs.

A. Figure MWN-2 provides the Company's current residential basic rate cost components, broken down by the energy, demand and customer cost classifications. In addition, the figure provides the associated residential basic rate revenue breakdown under the Company's current rate structure.

Figure MWN-2



	Cost Component ($MM)	Rate Component ($MM)
Energy	$64	$429
Demand	$370	$0
Customer	$46	$51

As shown in the cost breakdown column, approximately 77% of I&M's costs required to serve the residential class are fixed, demand-related costs, as classified by cost of service. Energy and customer-classified costs account for approximately 13% and 10% of total costs, respectively. In contrast, the basic rate component column illustrates that under the current residential rate structure, approximately 89% of total residential costs are recovered through volumetric energy charges, while approximately 11% of customer costs are recovered through the fixed monthly service charge.

Q. What conclusions can be drawn from Figure MWN-2?

A. Figure MWN-2 illustrates a clear mismatch between I&M's current cost components and the current rate components associated with serving the residential customer class. In other words, the Company's collection of revenues, largely recovered through volumetric charges, does not align with the predominately fixed cost of providing electric service to residential customers. Ideally, the rate structure for a residential customer would recover energy costs through an energy charge, customer costs through a fixed monthly service charge and demand costs through a demand charge. Such a three-part rate design better reflects cost causation than today's two-part rate design which relies heavily upon a volumetric energy charge to recover a disproportionate amount of fixed costs. However, as discussed above, the vast majority of I&M's residential customers are not currently demand-metered; therefore, demand-related costs cannot be recovered through demand charges today.

Q. Please discuss some of the inherent problems with today's Tariff R.S. rate structure relative to the cost components required to serve the residential customer class.

A. Today's Tariff R.S. rate structure presents several challenges for both customers and the Company alike. First, given the weather-sensitive nature of the customer class' energy usage, residential customers' monthly bills are subject to greater volatility when a disproportionate amount of fixed costs are included in the volumetric energy charge. Consequently, there is a potential for the Company to significantly over- or under-collect its fixed costs when actual weather presents extreme temperature deviations from the estimated Test Year weather assumptions.

Second, today's Tariff R.S. rate design does not send price signals that effectively reflect the underlying nature of the costs incurred to serve the Company's residential customers. This can create problems when a customer makes investments to reduce their energy usage and expect equal and offsetting reductions in the costs required for service. For example, the current Tariff R.S. rate design that recovers the vast majority of fixed costs through volumetric charges, may signal to customers that for every dollar spent on energy efficiency, nearly one dollar can be saved on customers' bills. However, the actual savings to I&M, and its customers may fall significantly short of the amount invested. The fixed costs of I&M's poles, conductors, transformers, etc. still exist, even though the current rate design signals to customers that those costs can be avoided through purchases aimed at reducing energy usage. Thus, an improper price signal sent through rate design can lead to inefficient investment decisions by customers.

Third, a rate design that recovers a disparate amount of fixed costs through volumetric energy charges has the potential to introduce intra-class subsidies paid by high energy users to low energy users. For example, a customer who does not adequately insulate or weatherize the customer's home will likely use a greater amount of energy and may subsidize a customer in a similarly sized home that does install effective weatherization measures in order to use a lower amount of energy. Similarly, residential customers with seasonal or vacation homes who may only register normal usage during a few months of the year receive a subsidy from customers who use average or above average levels of energy, when a disproportionately high level of fixed costs are embedded in the volumetric energy charge.

Q. Please explain the Company's proposed changes to the standard residential tariff in this proceeding.

A. In order to better align the Company's cost of service with the revenues recovered from its residential customers, I&M proposes two primary changes to its standard residential rate design. First, the Company proposes to increase the standard residential tariff service charge from the current level of $10.50 per month to $15.00 per month. Second, I&M proposes to introduce a declining-block volumetric energy rate structure, where the customer's monthly usage above 900 kWh are charged at a lower cents-per-kWh rate than the rate for any energy used up to 900 kWh. The objective of both changes is improved alignment between the

Company's costs incurred to serve the residential customer class and the charges paid by residential customers taking service.

Q. How does the Company's proposed residential rate design better align the underlying class cost structure with the class rate structure?

A. Since demand-related costs do not vary with the amount of electricity consumed, it is appropriate to recover a greater proportion of those fixed costs through fixed charges, rather than recovering a disproportionate amount of those costs through volumetric, per-kWh charges. I&M's proposal to increase the amount of demand-related costs recovered through both the monthly service charge and a declining block energy rate structure is a next-best alternative rate design to one that recovers a proportionate amount of demand-related costs through a demand charge. While cost causation principles may support recovery of 100% of fixed costs through fixed charges, or a "straight fixed variable" ("SFV") rate design, that is not what the Company proposes in this case. Rather I&M's proposed declining block energy rate structure provides a compromise structure that maintains a large amount of fixed cost recovery through the volumetric kWh charge, but one that prices the higher usage block closer to the true variable cost of energy. Therefore, the Company's proposal in this proceeding improves the alignment of residential costs and rates without introducing a straight fixed variable rate design.

Q. Has I&M historically included declining block energy rate structures in its tariffs?

A. Yes. A number of the Company's commercial and industrial tariffs[4] have long included declining block energy rates, which are aimed, at least in part, to recover a greater proportion of fixed costs in the lower usage or first block rates.

Q. Please explain how the Company designed the proposed standard residential tariff rates?

A. As discussed above, I&M's current residential rate structure recovers all customer-related costs and a portion of demand-related costs in the monthly service charge. Under the proposed residential rate structure, the Company designed rates to recover all customer-related costs, plus the total secondary distribution costs, based on cost of service, through the combination of the $15.00 monthly service charge and the first block volumetric energy charge. The remainder of the Company's total residential costs were designed to be recovered through the slightly lower-priced second block energy rate. It's important to recognize that all three rate components were designed collectively to recover the fixed secondary distribution costs through the service charge and first block energy charge. Moreover, a change to one proposed rate component would necessitate a change to the other components to achieve the Company's intended price signals and proposed fixed cost recovery.

[4] Currently, Tariffs GS, LGS, and IP all include declining energy block rate structures.

Q. Why is it reasonable to recover a portion of distribution fixed costs through the combination of the proposed monthly service charge and first block energy charge?

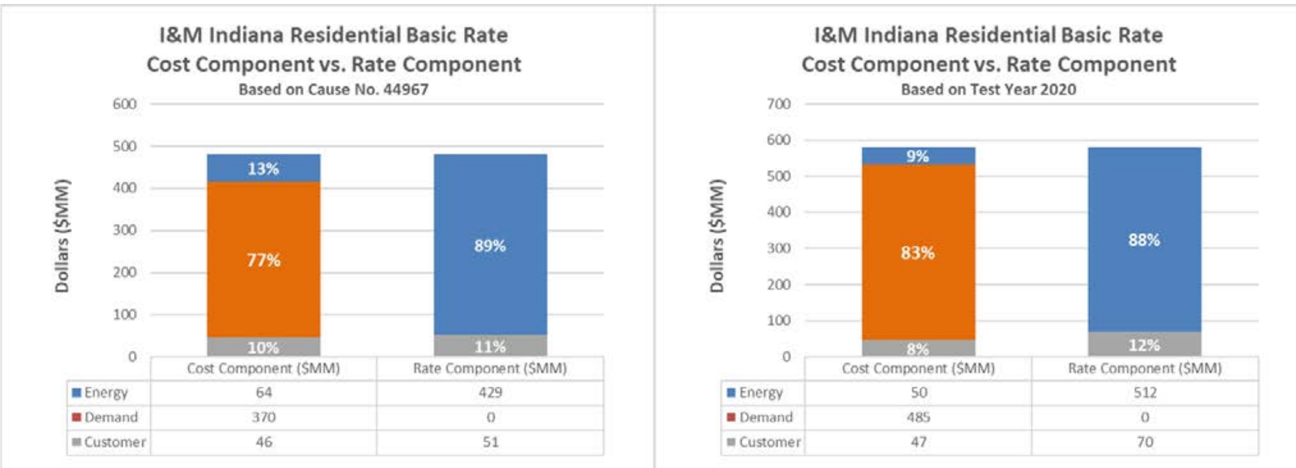
A. By designing the residential monthly service charge and first block energy charge to recover all secondary distribution costs along with customer-related costs, the Company has better aligned the collection of those costs with the local, fixed nature of those costs. Secondary distribution costs, such as the poles, wires and transformers seen in neighborhoods, represent those costs closest to the customer and those costs that are required to connect the customer to the higher voltage grid. Secondary distribution fixed costs would ideally be recovered from residential customers through demand charges, as they are typically collected from commercial and industrial customers. However, until demand metering is in place for all residential customers, collection of these costs through a combination of a monthly service charge and first block energy charge is more reasonable than through an all-kWh energy charge.

Q. How does I&M's proposed residential class cost components compare to the Company's proposed Tariff RS rate components?

A. Figure MWN-3 compares the Company's proposed residential basic rate cost components, to the proposed Tariff RS rate components. As illustrated in Figure MWN-3, the proposed cost component proportions are similar to the Company's currently authorized residential cost components presented in Figure MWN-2. In terms of rate components, Figure MWN-3 shows a slight increase in the proportion of demand-related costs now recovered in the monthly service charge, versus the amount of demand-related costs recovered in the current monthly service charge. The remainder of all proposed demand- and energy-related costs (88%) are recovered in the volumetric energy charges. The Company does not propose to recover any costs through a demand charge under Tariff RS.

Figure MWN-3

Current **Proposed**



Q. Does the Company's declining block energy rate conform with the Commission's guidance regarding PURPA?

A. Yes. In its decision in Cause No. 35780-S3, the Commission found that the PURPA declining block rate standard refers only to the energy cost component of a utility:

> The Commission now finds that said Declining Block Rate Standard should be implemented by I&M. The Commission further finds that said Declining Block Rate Standard refers only to the energy component of a rate and as such does not prohibit Declining Block Rates which reflect the recovery of customer and demand related costs. Nor does it bar Declining Block Rates that reflect declining energy costs that may actually be associated with increased consumption.

> The Declining Block Rates of I&M reflect declining costs that results from non-energy related determinates. Therefore, the Commission now finds that I&M's existing rates meet the Declining Block Rate Standard established by the PURPA.[5]

I&M's declining block volumetric rate proposal in this proceeding is consistent with the Commission's decision in Cause No. 35780-S3, since both volumetric block rates collect the same amount of energy-related costs, approximately 1.2 cents/kWh.

Q. Does the Company's proposed Tariff RS rate design provide benefits to residential customers?

A. Yes. First, by recovering a more proportionate amount of fixed demand-related costs in the fixed monthly service charge and first block of the volumetric energy charge, the Company's proposed rate design sends more accurate price signals to residential customers than under the current rate structure. A result of the Company's proposal is to provide a volumetric energy rate to customers that more closely reflects the actual energy cost component. Thus, the proposed rate design allows customers to make more informed decisions regarding the benefits of their energy usage relative to the true cost of their usage. As the Commission has previously recognized:

> Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided.[6]

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[5] In the Matter of the Determination of Proceedings Necessary by the Public Service Commission of Indiana to Fully Comply with the Requirements of the Public Utility Regulatory Policies Act (with Specific Reference to Indiana & Michigan Electric Company), Cause No. 35780-S3, Order dated November 21, 1981.
[6] 44576 Order at 72.

Second, the combination of lower volumetric energy charges, declining block rates and increased customer charges provides greater month-to-month bill stability for residential customers that are sensitive to weather extremes. The Commission also recognized this benefit in its decision in IPL's basic rate case, Cause No. 44576:

> We have also increased the customer charge in IPL's proposed rate design, which will reduce volatility by making the bill less reliant on volumetric charges.[7]

Q. Does the Company's residential rate design adhere to the principle of gradualism?

A. Yes. As discussed above, I&M's proposed residential rate design provides a gradual increase in the level of fixed, demand-related costs recovered through the monthly fixed service charge, while it continues to recover all energy- and the remaining fixed demand-related costs through the volumetric energy charge. Importantly, it should be recognized that the percentage increase in the monthly service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, "gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill."[8]

Q. Has the Company considered the impact of its residential rate design on low income customers?

A. Yes. A common misconception is that low income customers use significantly less energy than average or above average income customers. Under this premise, a

[7] Order and Findings, IURC Cause No. 44576, at 42.
[8] 44576 Order at 72

rate design that collects more fixed costs through fixed charges or through declining block energy charges would disadvantage low income customers, as compared to one that collects a higher level of fixed costs through uniform volumetric charges. However, low income does not necessarily equate to low energy consumption among residential customers. Like other residential customers, low income customers are weather-sensitive energy customers. Some may need to keep their homes warmer in the winter or cooler in the summer because of medical or other needs. Therefore, collecting a disproportionate amount of fixed costs through volumetric charges can expose these customers to more severe bill impacts during periods of weather extremes.

Q. Does the Company have information that supports the assertion that low income does not necessarily correlate to low usage?

A. Yes. A review of 2018 Company data illustrates that I&M's Indiana residential customers on assistance programs use noticeably similar amounts of annual energy as compared to those residential customers that are not on assistance programs. Figure MWN-4 below shows the average usage for I&M's Indiana residential assistance and non-assistance customers and provides evidence that I&M's average assistance customer used within approximately 5% of the annual usage of I&M's average non-assistance customer.

Figure MWN-4

Mon-Yr	Average Assistance Usage (kWh)	Average Non-Assistance Usage (kWh)	Assistance / Non-Assistance %
Jan-18	1,296	1,280	1.3%
Feb-18	1,048	1,029	1.9%
Mar-18	904	894	1.1%
Apr-18	874	867	0.9%
May-18	648	689	-6.0%
Jun-18	750	860	-12.8%
Jul-18	893	1,048	-14.7%
Aug-18	830	990	-16.1%
Sep-18	836	993	-15.8%
Oct-18	670	760	-11.9%
Nov-18	778	751	3.6%
Dec-18	1,079	1,014	6.4%
Average	884	931	-5.2%

Furthermore, in the winter months, the average assistance user used roughly the same amount or more electricity than the average non-assistance customer. This suggests that a significant portion of I&M's Indiana assistance customers rely on electricity for their winter space heating needs. More importantly, the data suggests that the Company's proposal to recover a more proportional amount of fixed costs through both the fixed service charge and declining block energy charge can actually benefit the average assistance customer during the winter months when they rely on electricity the most.

Q. Has the Commission provided a recent finding that is consistent with the Company's residential assistance customer usage data?

A. Yes. At page 72 of its Order in Cause No. 44576, the Commission noted: "Many low-income customers use more than the residential average amount."

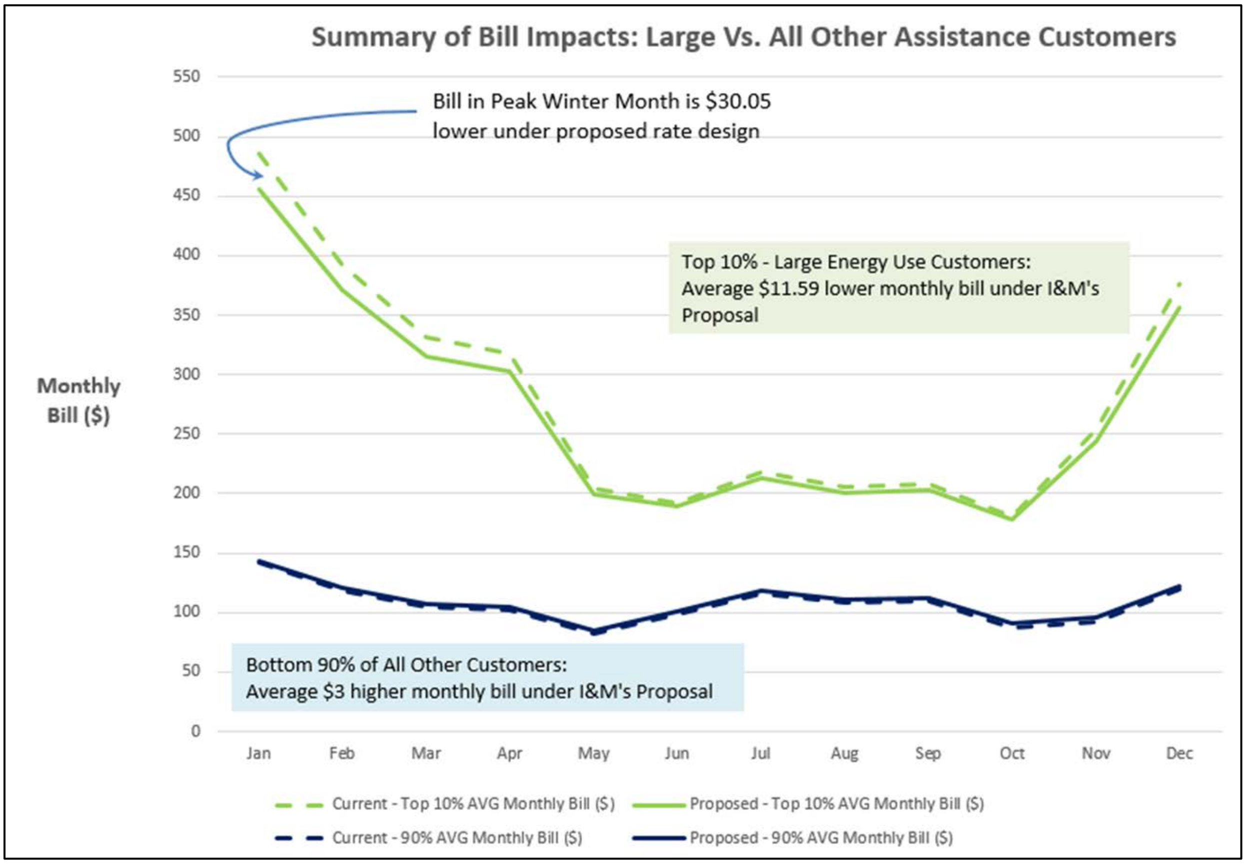
Q. Has the Company evaluated the potential bill impacts under both its proposed and current rate designs relative to low income customers?

A. Yes. I compared the estimated bill impacts to I&M's assistance customers under both the proposed residential rate design and under a rate design that maintains the current $10.50 per-month service charge and a uniform kWh rate. Both the proposed and current rate designs were based on Test Year cost of service and billing determinant data. To assess the bill impacts of both designs, I applied the rates from each rate design to the 2018 historic assistance customer usage data for all customers with 12 months of recorded usage. More specifically, my analysis compared the bill impacts on I&M's large usage assistance customers, defined as the top 10% of assistance customers by 2018 annual energy (kWh) usage, to the bill impacts on the remaining 90% of assistance customers. This segmentation of customers helps illustrate the benefits of I&M's proposed rate design to those large-use assistance customers who rely on electricity the most.

Q. Please discuss the results of your analysis that compares I&M's proposed and current residential rate designs as they apply to low income customers.

A. Figure MWN-5 summarizes the bill impacts of I&M's proposed and current residential rate designs applicable to both the top 10% of assistance customers and to all other assistance customers. As illustrated in Figure MWN-5, the Company's proposal provides a bill reduction to the average large assistance customer of over $11.00 per month when compared to the current residential rate design. Moreover, the average savings to the large assistance customer during the peak winter month of December is over $30. Conversely, when compared to the current rate design, the Company's proposal results in an average bill increase of less than $3 per month for the remaining 90% of assistance customers.

Figure MWN-5



<u>**OPTIONAL RESIDENTIAL DEMAND-METERED TARIFF**</u>

Q. Please describe the Company's proposed optional residential demand-metered tariff.

A. As discussed by Company witness Cooper, I&M is proposing a new optional residential rate schedule, called Residential Service - Demand Metered (Tariff RSD). This optional tariff is available as a pilot program available to up to 4,000 customers, which is approximately 1% of I&M's current residential customers and utilizes a three-part rate structure which includes a monthly service charge, a kWh energy charge, and an on-peak kW demand charge. The on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

Q. What is the Company's objective associated with offering Tariff RSD?

A. The goal of this optional rate structure is two-fold. First, Tariff RSD is designed to provide a rate structure that is more reflective of the Company's residential class cost structure as described above. Thus, by offering a three-part rate comprised of a $-month service charge, a cents-per-kWh energy charge and a $-kW demand charge, Tariff RSD sends customers a clear price signal that better reflects cost causation as compared to a signal sent by a two-part rate design. The improved price signal results from the fact that a level of demand-related costs are recovered through a demand charge, instead of through a volumetric energy charge. Second, and related to the first goal, Tariff RSD provides I&M's residential customers with an additional tariff option to manage their monthly bills. Under the Company's current standard residential rate structure, which features a two-part rate design, customers are limited to increasing or decreasing their electricity usage to change the total amount of their monthly bill. Under Tariff RSD, customers are provided a demand charge as a third dimension to control their bills by managing the peak intensity of their use.

Q. Please explain how the Company designed the proposed Tariff RSD rates.

A. The rates for Tariff RSD were calculated on a revenue-neutral basis relative to the existing residential tariff class, using the residential class target revenues and billing determinants proposed in this case. To achieve this, I first solved for the proposed on-peak demand-related revenues to be recovered by the Tariff RSD demand charge. Demand-related revenues for Tariff RSD are the sum of all distribution secondary, plus 25% of distribution primary, plus all customer-related revenues from class cost of service, less any revenues collected through proposed monthly RSD service charge. The resulting on-peak demand-related revenues were divided by the residential class on-peak billing demand, measured in kW. The on-peak billing demand represents the residential class sigma non-coincident peak obtained from the load research data utilized in this case. Next, I solved for the proposed energy-related revenues by subtracting any customer- and demand-related revenues from above. The resulting energy revenue was divided by the residential class energy, measured in kWh, to compute the volumetric energy charge. WP-MWN-4 provides the detailed calculations used to develop Tariff RSD demand, energy and service charges.

<u>OTHER RATE DESIGN TOPICS</u>

Q. Please describe the basic rate design proposal shown on Workpaper WP-MWN-4.

A. Workpaper WP-MWN-4 provides the Company’s proposed basic rate design computations based on the proposed sales revenues contained in Workpaper WP-MWN-3.

Q. Please explain the proposed changes to tariff classes Municipal Service (MS), Electric Heat General (EHG) and Water and Sewage Service (WSS).

A. For tariffs MS, EHG and WSS, the Company proposes to include demand charges, based on customers’ registered monthly demand in kW, taken each month as the single-highest 15-minute integrated peak in kW, as registered during the month by a 15-minute integrating demand meter or indicator. For each tariff, the proposed demand charge was set at the proposed Tariff GS Secondary demand charge to facilitate the transition to the proposed rate structure. The proposed tariffs MS, EHG and WSS tariffs align with the Company's general rate design objective of recovering proportional amounts of fixed costs through fixed and/or demand charges.

Q. Please describe the rider factor computations for current rider rate designs shown on Workpaper WP-MWN-5.

A. Workpaper WP-MWN-5 provides the rider factor computations for each of the Company's existing riders during the Test Year under the current rider rate designs. The rider revenue requirements for all existing riders other than the Demand-Side Management / Energy Efficiency Program Cost Rider (DSM/EE), are based on the costs contained in the Company's financial forecast and are supported by Company witness Williamson.[9] The resulting factors are used to compute the current revenues in Company witness Duncan's Detail of Present and Proposed Revenues schedule, Attachment JCD-2.

Q. Please describe the rider factor computations for proposed rider rate designs shown on Workpaper WP-MWN-6.

A. Workpaper WP-MWN-6 provides the proposed rate designs for riders in effect during the Test Year and the resulting rider factors for the OSS & PJM Cost Rider

[9] The current DSM/EE Rider revenue requirement is based on the level of revenues collected through the 2019 DSM/EE rider rates in effect at the time of filing, adjusted for an increased level of Net Lost Revenue, as explained by Company witness Williamson.

(OSS/PJM Rider) and DSM Rider based on the proposed rider revenue requirements supported by Company witnesses Williamson. The resulting factors for both riders are used to compute the total proposed revenues in Company witness Duncan's Detail of Present and Proposed Revenues schedule, Attachment JCD-2; however, as explained by Company witness Williamson and as reflected in I&M's proposed tariff sheets, I&M will update rider factors pursuant to the Commission's order in this basic rate case.

Specific to the OSS/PJM Rider, Environmental Cost Rider, Resource Adequacy Rider and Life Cycle Management Rider, I designed the rider factors for Tariffs MS, EHG and WSS to include both a cents/kWh energy factor and a $/kW demand factor, similar to the current OSS/PJM Rider factors applicable to Tariffs LGS and IP. The designed rider factors for these tariffs better align with the classification of costs and the way in which they would be recovered through basic rates.

Q. Please explain the rate design for I&M's proposed Advanced Metering Infrastructure (AMI) Rider.

A. As explained by Company witness Williamson, the proposed AMI rider will recover I&M's AMI deployment costs. Given the customer-nature of those costs, the proposed AMI rider rate design allocates these costs among customer classes on the Distribution Meters allocation factors taken from Company witness High's class cost of service study. Customer classes are divided into five categories: Residential, Small Commercial and Street Lighting, Medium and Large

Commercial, Industrial and Non-metered.[10] Since the costs associated with AMI deployment are meter-related, no costs are allocated to the Non-metered customer class. Following the allocation of costs to the customer classes, factors are computed on a per-bill basis. The proposed AMI Rider rate design is included in WP-MWN-6.

RATE DESIGN OF PHASE-IN RATE ADJUSTMENT

Q. Please provide an overview of the rate design associated with I&M's proposed Phase-In Rate Adjustment (PRA) factors.

A. As explained by Company witness Duncan, I&M's proposed Phase-In Rate Adjustment consists of two components: (a) a rate credit associated with revenues received from the IMMDA wholesale contracts and (b) a rate credit to reflect forecasted plant additions during the Test Year. Using both components, one distinct set of adjustment factors was computed to coincide with each time period, or phase, that the respective credits are in effect. The proposed Phase-In Rate Adjustment rate design is based on the same rate structure as I&M's current Phase-In Rate Adjustment, with demand charges added for tariffs EHG, MS and WSS. Workpaper WP-MWN-7 provides the PRA factor rate design.

[10] Small Commercial and Street Lighting class consists of Tariffs: GS, IS, EHG, MS, WSS and SLCM. Medium and Large Commercial class consists of Tariff LGS. Transmission voltage level customers are excluded from AMI installations; thus, excluded from the AMI Rider rate design.

COMPARATIVE BILLING ANALYSIS AND TYPICAL BILLS

Q. Have you prepared a comparison of billing under forecast current and proposed rates?

A. Yes, Attachment MWN-4 presents a comparison of typical bills under present and proposed rate structures at the end of the Test Year for each of the major tariff classes at a range of usage levels. The current rates on Attachment MWN-4 reflect I&M's basic rates as of this filing and the Company's existing riders as presented in Workpaper WP-MWN-5. The proposed rates on Attachment MWN-4 reflect the Company's proposed end of period basic rates and the effect of the rider changes proposed in this case as presented in WP-MWN-6.

Q. Please explain the effect of I&M's proposed Phase-In Rate Adjustment on a residential customer during the Test Year.

A. Figure MWN-6 illustrates the effect of the Company's Phase-In Rate Adjustment on a residential customer that uses 1,000 kWh per month. A total monthly bill impact in dollars and cumulative percentage increase is shown for each of the three distinct periods under the Company's proposal.

Figure MWN-6

		Phase-In Rate Adjustment Bill Impact		
Residential at 1,000 kWh-month	Current	Prior to Jun-1, 2020	Jun-1, 2020	Jan-1, 2021
Total Bill ($)	$141.91	$ 153.51	$ 158.03	$ 163.02
Cumulative Increase ($)		$ 11.60	$ 16.12	$ 21.11
Cumulative Increase (%)		8.2%	11.4%	14.9%

Q. Does this conclude your pre-filed verified direct testimony?

A. Yes.

VERIFICATION

I, Matthew W. Nollenberger, Manager, Regulated Pricing and Analysis of American Electric Power Service Corporation (AEPSC), affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 8-MAY-2019

Matthew W. Nollenberger

Matthew W. Nollenberger

Test Year Transmission Owner (TO) Cost and Revenue Calculation 1/

1. Remove Embedded Cost of Service - Transmission (BulkTran + SubTran)

Total Rate Base	$863,569,940	
Proposed Rate of Return	5.86%	2/
Income Requirement	$50,617,036	
Total Expense	$54,643,601	
Incremental Taxes	$6,662,873	

Embedded COS TO Revenue Requirement	$111,923,510

2. Remove PJM and Other TO Revenues - Transmission (BulkTran + SubTran)

Total Other Revenues	$115,832,728
TO Cost & Revenue Adjustment	$3,909,218

1/ Source: WP-DEH-4, unless noted otherwise
2/ Source: Attachment MWN-2, = Proposed Operating Income/Proposed Rate Base

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2020

Current Class (1)	Adjusted COS Current Revenue (2)	Continuing Rider Revenue (3)	Total Revenue (4) = (2) + (3)	Current ROR % (5)	Current ROR Index (6)	Proposed Basic Rate Increase (7) = (8) - (2)	Proposed Basic Rate Revenue (8)	Rider Revenue (9)	Total Revenue (10) = (8) + (9)	% Increase (11) = (10) / (4)	Proposed ROR % (12)	Proposed ROR Index (13)
RS	500,722,762	95,033,764	595,756,526	3.18	93	81,246,428	581,969,190	96,474,544	678,443,734	13.88%	5.68	97
GS	149,660,353	32,822,523	182,482,876	4.38	128	17,827,582	167,487,934	33,109,645	200,597,579	9.93%	6.58	112
LGS	233,811,510	40,304,246	274,115,756	3.48	102	32,645,177	266,456,687	40,778,433	307,235,120	12.08%	5.91	101
IP	239,751,610	47,374,871	287,126,481	2.93	86	34,342,115	274,093,725	46,397,351	320,491,076	11.62%	5.49	94
MS	3,058,727	598,770	3,657,497	3.55	104	431,174	3,489,901	546,657	4,036,558	10.36%	5.96	102
WSS	9,222,581	1,569,097	10,791,678	4.01	118	1,119,307	10,341,888	1,411,224	11,753,112	8.91%	6.30	108
IS	137,952	24,493	162,445	11.38	334	12,205	150,157	12,288	162,445	0.00%	13.85	236
EHG	701,451	147,773	849,224	5.38	158	65,706	767,157	135,430	902,587	6.28%	7.33	125
OL	6,169,229	194,420	6,363,649	8.53	250	410,837	6,580,066	(57,264)	6,522,802	2.50%	9.69	165
SL	5,441,923	309,477	5,751,400	11.27	331	379,840	5,821,763	(70,363)	5,751,400	0.00%	12.83	219
Subtotal	1,148,678,098	218,379,433	1,367,057,532	3.41	100	168,480,371	1,317,158,469	218,737,945	1,535,896,414	12.35%	5.86	100
Interruptible	94,345,014	3,013,885	97,358,899			3,270,755	97,615,769	2,908,899	100,524,668	3.25%		
Total Basic Rates	1,243,023,112					171,751,126	1,414,774,238				5.91	
Riders	221,393,319	221,393,319				253,525	221,646,844	221,646,844				
Total	1,464,416,431		1,464,416,431			172,004,651	1,636,421,081		1,636,421,082	11.75%		

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2020

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Current Equalized Rate of Return: Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)=(2)-(11)
RS	500,722,762	2,321,570,105	73,764,757	3.18	1.50	7,486,197	5,506,176	79,270,934	3.41	508,208,959	(7,486,197)
GS	149,660,353	616,632,096	27,024,802	4.38	-5.42	(8,116,341)	(5,969,654)	21,055,148	3.41	141,544,012	8,116,341
LGS	233,811,510	972,566,108	33,848,520	3.48	-0.37	(869,959)	(639,864)	33,208,656	3.41	232,941,551	869,959
IP	239,751,610	934,379,255	27,365,985	2.93	2.57	6,170,907	4,538,767	31,904,751	3.41	245,922,517	(6,170,907)
MS	3,058,727	13,000,204	461,538	3.55	-0.78	(23,985)	(17,641)	443,897	3.41	3,034,742	23,985
WSS	9,222,581	36,386,963	1,459,483	4.01	-3.20	(295,082)	(217,036)	1,242,447	3.41	8,927,499	295,082
IS	137,952	469,700	53,450	11.38	-36.87	(50,866)	(37,412)	16,038	3.41	87,086	50,866
EHG	701,451	2,764,297	148,826	5.38	-10.55	(74,014)	(54,438)	94,388	3.41	627,437	74,014
OL	6,169,229	27,585,622	2,353,166	8.53	-31.10	(1,918,726)	(1,411,244)	941,922	3.41	4,250,503	1,918,726
SL	5,441,923	21,607,850	2,435,464	11.27	-42.41	(2,308,131)	(1,697,655)	737,809	3.41	3,133,792	2,308,131
Total	1,148,678,098	4,946,962,201	168,915,990	3.41	0.00	0	(0)	168,915,990	3.41	1,148,678,098	0

Gross Rev Conversion Factor: 1.3596

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2020

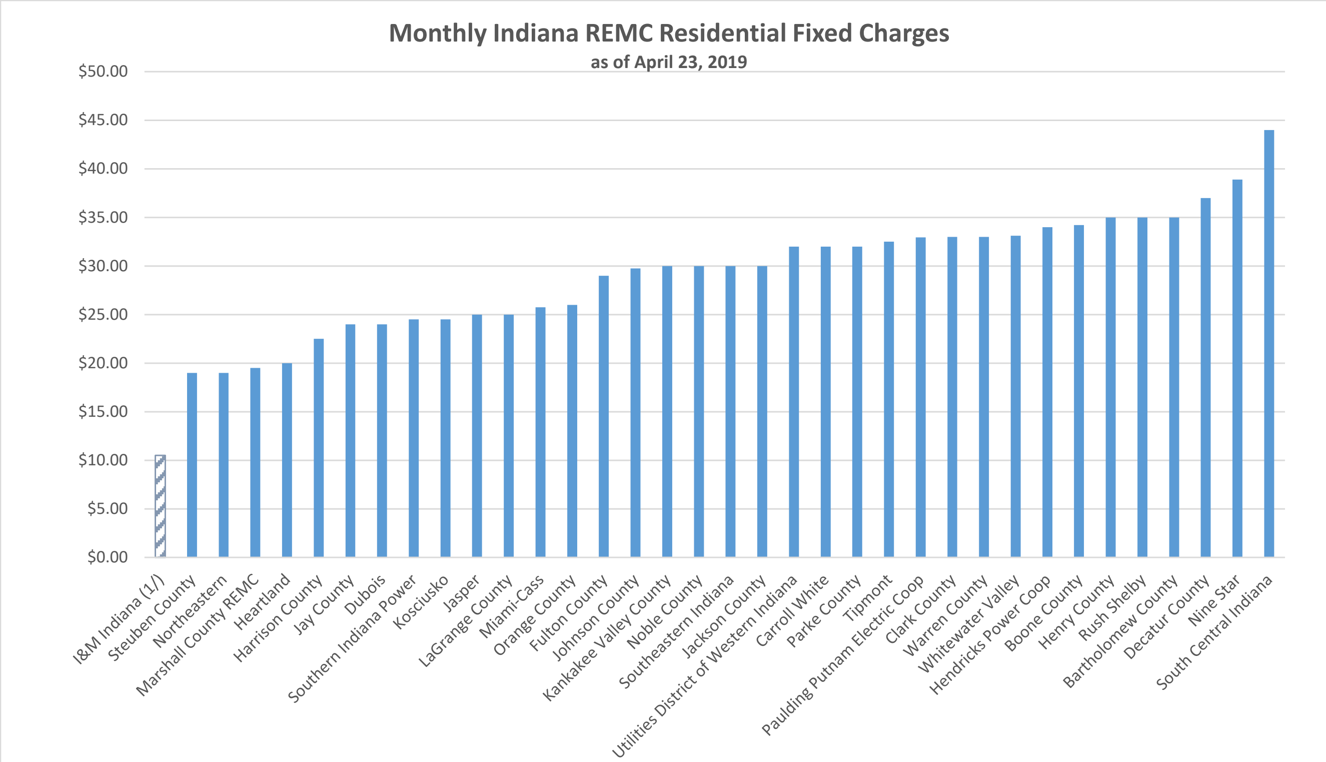
					Proposed Equalized Rate of Return						Retain 75% of	Increase	MIN Total	
Current Class	Current Revenue	Rate Base	Current Income	Current ROR %	Percent Increase	Revenue Increase	Income Increase	Proposed Income	ROR %	Sales Revenue	Current Subsidy	Before MIN Increase	Increase = 0%	Proposed Increase
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)=(7)+(12)+(14)
RS	500,722,762	2,321,570,105	73,764,757	3.18	16.92	84,718,135	62,311,073	136,075,830	5.86	585,440,897	(5,614,648)	82,842,400	(155,191)	78,948,296
GS	149,660,353	616,632,096	27,024,802	4.38	8.28	12,397,229	9,118,291	36,143,093	5.86	162,057,582	6,087,256	18,155,924	(41,220)	18,443,265
LGS	233,811,510	972,566,108	33,848,520	3.48	13.47	31,484,509	23,157,185	57,005,705	5.86	265,296,019	652,469	33,184,378	(65,014)	32,071,964
IP	239,751,610	934,379,255	27,365,985	2.93	15.54	37,255,007	27,401,447	54,767,432	5.86	277,006,617	(4,628,181)	33,427,056	(62,461)	32,564,365
MS	3,058,727	13,000,204	461,538	3.55	13.36	408,494	300,452	761,990	5.86	3,467,221	17,989	379,930	(869)	425,614
WSS	9,222,581	36,386,963	1,459,483	4.01	9.93	915,408	673,292	2,132,775	5.86	10,137,989	221,312	963,866	(2,432)	1,134,288
IS	137,952	469,700	53,450	11.38	-25.55	(35,240)	(25,919)	27,531	5.86	102,712	38,150	(12,890)	12,890	15,800
EHG	701,451	2,764,297	148,826	5.38	2.56	17,947	13,200	162,026	5.86	719,398	55,511	53,547	(185)	73,273
OL	6,169,229	27,585,622	2,353,166	8.53	-16.23	(1,001,033)	(736,271)	1,616,895	5.86	5,168,196	1,439,045	160,997	(1,844)	436,168
SL	5,441,923	21,607,850	2,435,464	11.27	-29.20	(1,589,303)	(1,168,949)	1,266,515	5.86	3,852,620	1,731,097	(316,327)	316,327	458,121
Total	1,148,678,098	4,946,962,201	168,915,990	3.41	14.33	164,571,153	121,043,802	289,959,792	5.86	1,313,249,251	0	168,838,883	0	164,571,153
						164,571,153		289,959,792						

Gross Rev Conversion Factor:	1.3596
Jurisdictional Revenue Deficiency* (A-1):	167,841,908
*(Before TO Cost Revenue Adjustment)	
Less Juris IRP (Att. MWN-2 P.1)	(3,270,755)
	164,571,153

Indiana Michigan Power Company
Proposed Revenue Allocation
Twelve Months Ending December 31, 2020

					Proposed Revenue Allocation							
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	Proposed Revenue (10)	Adjust for TO Cost/Revenue (11)	Adj. Proposed Revenue (12)	ROR % (13)
RS	500,722,762	2,321,570,105	73,764,757	3.18	15.77	78,948,296	58,067,297	131,832,054	579,671,058	2,298,132	581,969,190	5.68
GS	149,660,353	616,632,096	27,024,802	4.38	12.32	18,443,265	13,565,214	40,590,016	168,103,618	(615,683)	167,487,934	6.58
LGS	233,811,510	972,566,108	33,848,520	3.48	13.72	32,071,964	23,589,265	57,437,785	265,883,474	573,213	266,456,687	5.91
IP	239,751,610	934,379,255	27,365,985	2.93	13.58	32,564,365	23,951,431	51,317,416	272,315,975	1,777,750	274,093,725	5.49
MS	3,058,727	13,000,204	461,538	3.55	13.91	425,614	313,044	774,582	3,484,341	5,560	3,489,901	5.96
WSS	9,222,581	36,386,963	1,459,483	4.01	12.30	1,134,288	834,280	2,293,763	10,356,868	(14,980)	10,341,888	6.30
IS	137,952	469,700	53,450	11.38	11.45	15,800	11,621	65,071	153,752	(3,595)	150,157	13.85
EHG	701,451	2,764,297	148,826	5.38	10.45	73,273	53,893	202,719	774,724	(7,568)	767,157	7.33
OL	6,169,229	27,585,622	2,353,166	8.53	7.07	436,168	320,806	2,673,972	6,605,397	(25,331)	6,580,066	9.69
SL	5,441,923	21,607,850	2,435,464	11.27	8.42	458,121	336,953	2,772,417	5,900,044	(78,281)	5,821,763	12.83
Total	1,148,678,098	4,946,962,201	168,915,990	3.41	14.33	164,571,153	121,043,804	289,959,794	1,313,249,251	3,909,218	1,317,158,469	5.86

Gross Rev Conversion Factor: 1.3596



REMC	Monthly Residential Fixed Charge	REMC	Monthly Residential Fixed Charge
I&M Indiana (1/)	$10.50	Southeastern Indiana	$30.00
Steuben County	$19.00	Jackson County	$30.00
Northeastern	$19.00	Utilities District of Western Indiana	$32.00
Marshall County REMC	$19.50	Carroll White	$32.00
Heartland	$20.00	Parke County	$32.00
Harrison County	$22.50	Tipmont	$32.50
Jay County	$24.00	Paulding Putnam Electric Coop	$32.95
Dubois	$24.00	Clark County	$33.00
Southern Indiana Power	$24.50	Warren County	$33.00
Kosciusko	$24.50	Whitewater Valley	$33.11
Jasper	$25.00	Hendricks Power Coop	$34.00
LaGrange County	$25.00	Boone County	$34.20
Miami-Cass	$25.75	Henry County	$35.00
Orange County	$26.00	Rush Shelby	$35.00
Fulton County	$29.00	Bartholomew County	$35.00
Johnson County	$29.75	Decatur County	$37.00
Kankakee Valley County	$30.00	Nine Star	$38.89
Noble County	$30.00	South Central Indiana	$44.00
		Median	$30.00

1/ Included for comparison purposes

Indiana Michigan Power Company - Indiana
Typical Electric Bill Comparison

Line No.	Tariff	Demand	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
	RS						
1		--	250	$43.35	$52.24	$8.89	20.5%
2	Proposed Only	--	500	$76.22	$89.47	$13.25	17.4%
3	Block 1 - up to 900 kWh	--	750	$109.05	$126.69	$17.64	16.2%
4	Block 2 - all other kWh	--	1,000	$141.91	$163.02	$21.11	14.9%
5		--	2,000	$273.32	$302.82	$29.50	10.8%
6		--	4,000	$536.16	$582.42	$46.26	8.6%
	RS-OPES						
7	On-Peak 30%	--	250	$39.76	$47.54	$7.78	19.6%
8	Off-Peak 70%	--	500	$68.06	$78.59	$10.53	15.5%
9		--	750	$96.30	$109.62	$13.32	13.8%
10		--	1,000	$124.58	$140.67	$16.09	12.9%
11		--	2,000	$237.65	$264.84	$27.19	11.4%
12		--	4,000	$463.82	$513.19	$49.37	10.6%
	RS-TOD						
13	On-Peak 30%	--	500	$68.06	$78.59	$10.53	15.5%
14	Off-Peak 70%	--	1,000	$124.58	$140.67	$16.09	12.9%
15		--	2,000	$237.65	$264.84	$27.19	11.4%
16		--	3,000	$350.76	$389.01	$38.25	10.9%
17		--	4,000	$463.82	$513.19	$49.37	10.6%
18		--	5,000	$576.90	$637.36	$60.46	10.5%
	RS-TOD2						
19	On-Peak 5%	--	500	$74.36	$85.80	$11.44	15.4%
20	Off-Peak 95%	--	1,000	$138.18	$156.60	$18.42	13.3%
21		--	2,000	$265.86	$298.20	$32.34	12.2%
22		--	3,000	$393.57	$439.80	$46.23	11.7%
23		--	4,000	$521.24	$581.41	$60.17	11.5%
24		--	5,000	$648.92	$723.02	$74.10	11.4%
	GS-SEC <10 kW						
25	Block 1 - up to 4,500 kWh	3 kW	250	$52.01	$56.61	$4.60	8.8%
26	Block 2 - all other kWh	3 kW	500	$85.03	$94.22	$9.19	10.8%
27		5 kW	1,000	$151.04	$169.44	$18.40	12.2%
28		7 kW	2,500	$349.11	$395.10	$45.99	13.2%
29		9 kW	5,000	$664.50	$751.72	$87.22	13.1%
	GS-TOD2						
30	On-Peak 5%	--	1,000	$145.35	$164.44	$19.09	13.1%
31	Off-Peak 95%	--	2,500	$334.88	$382.60	$47.72	14.2%
32		--	5,000	$650.74	$746.21	$95.47	14.7%
33		--	7,500	$966.61	$1,109.80	$143.19	14.8%
	GS-OUSP						
34	Optional Unmetered	--	100	$20.25	$22.61	$2.36	11.7%
35	Service Provision	--	250	$38.94	$44.52	$5.58	14.3%
36		--	500	$70.09	$81.04	$10.95	15.6%
37		--	1,000	$132.36	$154.09	$21.73	16.4%
38		--	2,000	$256.94	$300.18	$43.24	16.8%
	GS-SEC						
39	Block 1 - up to 4,500 kWh	10 kW	2,000	$283.09	$319.89	$36.80	13.0%
40	Block 2 - all other kWh	10 kW	3,000	$415.13	$470.32	$55.19	13.3%
41		10 kW	4,000	$547.17	$620.76	$73.59	13.4%
42		10 kW	5,000	$664.50	$751.72	$87.22	13.1%
43		100 kW	20,000	$2,753.53	$3,027.47	$273.94	9.9%
44		100 kW	25,000	$3,266.73	$3,584.73	$318.00	9.7%
45		100 kW	30,000	$3,779.92	$4,141.98	$362.06	9.6%
46		500 kW	100,000	$13,406.65	$14,627.95	$1,221.30	9.1%

Indiana Michigan Power Company - Indiana
Typical Electric Bill Comparison

Line No.	Tariff	Demand	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
	GS-TOD-SEC						
47	On-Peak 40%	--	100	$30.11	$31.07	$0.96	3.2%
48	Off-Peak 60%	--	250	$46.77	$49.16	$2.39	5.1%
49		--	500	$74.55	$79.31	$4.76	6.4%
50		--	1,000	$130.08	$139.62	$9.54	7.3%
51		--	2,000	$241.18	$260.25	$19.07	7.9%
52		--	4,000	$463.34	$501.47	$38.13	8.2%
	GS-LM-TOD						
53	On-Peak 30%	--	500	$70.03	$73.81	$3.78	5.4%
54	Off-Peak 70%	--	1,000	$121.05	$128.61	$7.56	6.2%
55		--	2,000	$223.11	$238.22	$15.11	6.8%
		--	2,500	$274.13	$293.02	$18.89	6.9%
56		--	3,000	$325.15	$347.82	$22.67	7.0%
57		--	4,000	$427.20	$457.42	$30.22	7.1%
58		--	5,000	$529.25	$567.05	$37.80	7.1%
	GS-PRI						
59		300 kW	60,000	$7,457.71	$8,162.77	$705.06	9.5%
	GS-SUB						
60		100 kW	40,000	$4,332.07	$4,734.49	$402.42	9.3%
	LGS-SEC						
61	Block 1 - First 300 kWh/kVA	100 kW	30,000	$3,113.54	$3,504.42	$390.88	12.6%
62	Block 2 - all other kWh	100 kW	40,000	$3,607.96	$4,068.00	$460.04	12.8%
63		100 kW	50,000	$4,065.55	$4,569.99	$504.44	12.4%
64		100 kW	60,000	$4,523.15	$5,071.99	$548.84	12.1%
65		500 kW	150,000	$15,438.68	$17,392.90	$1,954.22	12.7%
66		500 kW	200,000	$17,915.09	$20,218.02	$2,302.93	12.9%
67		500 kW	250,000	$20,203.06	$22,727.99	$2,524.93	12.5%
68		500 kW	300,000	$22,491.03	$25,237.96	$2,746.93	12.2%
	LGS-PRI						
69		500 kW	150,000	$14,216.36	$16,055.73	$1,839.37	12.9%
70		500 kW	200,000	$16,618.61	$18,797.90	$2,179.29	13.1%
71		500 kW	250,000	$18,838.55	$21,234.04	$2,395.49	12.7%
72		500 kW	300,000	$21,058.49	$23,670.19	$2,611.70	12.4%
	LGS-SUB						
73		900 kW	150,000	$15,639.31	$17,001.50	$1,362.19	8.7%
74		900 kW	250,000	$21,346.23	$24,038.28	$2,692.05	12.6%
75		900 kW	350,000	$26,313.30	$29,832.53	$3,519.23	13.4%
76		900 kW	450,000	$30,689.48	$34,634.37	$3,944.89	12.9%
	LGS-TRAN						
77		100 kW	20,000	$2,054.13	$2,246.73	$192.60	9.4%
78		100 kW	25,000	$2,336.33	$2,594.76	$258.43	11.1%
79		100 kW	30,000	$2,618.55	$2,942.78	$324.23	12.4%
80		100 kW	35,000	$2,869.69	$3,238.68	$368.99	12.9%
	LGS-LM-TOD						
81	On-Peak 30%	--	15,000	$1,365.33	$1,536.14	$170.81	12.5%
82	Off-Peak 70%	--	25,000	$2,252.01	$2,536.69	$284.68	12.6%
83		--	35,000	$3,138.69	$3,537.24	$398.55	12.7%
	LGS-TOD-SEC						
84	On-Peak 45%	50 kW	20,000	$1,956.32	$2,175.91	$219.59	11.2%
85	Off-Peak 55%	100 kW	50,000	$4,561.33	$5,120.01	$558.68	12.2%
86		100 kW	60,000	$5,245.31	$5,923.48	$678.17	12.9%
	LGS-TOD-PRI						
87	On-Peak 40%	400 kW	150,000	$12,752.25	$14,627.90	$1,875.65	14.7%
88	Off-Peak 60%	400 kW	200,000	$15,757.50	$18,317.80	$2,560.30	16.2%
89		400 kW	250,000	$18,762.75	$22,007.70	$3,244.95	17.3%

Indiana Michigan Power Company - Indiana
Typical Electric Bill Comparison

Line No.	Tariff	Demand	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
	IP-SEC						
90	Block 1 - First 410 kWh/kVA	1,000 kVA	250,000	$31,525.09	$34,901.86	$3,376.77	10.7%
91	Block 2 - all other kWh	1,000 kVA	350,000	$36,787.52	$41,082.20	$4,294.68	11.7%
92		1,500 kVA	550,000	$56,439.39	$63,110.88	$6,671.49	11.8%
93		1,500 kVA	650,000	$61,157.68	$68,627.40	$7,469.72	12.2%
94		1,500 kVA	750,000	$62,133.59	$69,578.41	$7,444.82	12.0%
	IP-PRI						
95		3,000 kVA	1,000,000	$99,839.44	$111,235.57	$11,396.13	11.4%
96		3,000 kVA	1,500,000	$115,696.20	$129,771.82	$14,075.62	12.2%
97		3,000 kVA	2,000,000	$120,377.89	$134,353.15	$13,975.26	11.6%
	IP-SUB						
98		7,500 kVA	2,000,000	$201,216.19	$221,332.35	$20,116.16	10.0%
99		7,500 kVA	3,000,000	$250,270.03	$280,482.02	$30,211.99	12.1%
100		7,500 kVA	4,000,000	$266,903.38	$298,843.10	$31,939.72	12.0%
	IP-TRAN						
101		7,500 kVA	3,000,000	$249,565.93	$277,928.42	$28,362.49	11.4%
102		7,500 kVA	4,000,000	$266,051.43	$296,065.05	$30,013.62	11.3%
103		10,000 kVA	6,000,000	$360,701.77	$400,615.95	$39,914.18	11.1%
	MS						
104		40 kW	8,000	$985.20	$1,156.15	$170.95	17.4%
105		40 kW	10,000	$1,226.16	$1,323.99	$97.83	8.0%
106		40 kW	12,000	$1,467.12	$1,491.83	$24.71	1.7%
	WSS-SEC						
107		50 kW	15,000	$1,235.90	$1,473.70	$237.80	19.2%
108		50 kW	17,500	$1,438.85	$1,620.08	$181.23	12.6%
109		50 kW	20,000	$1,641.80	$1,766.45	$124.65	7.6%
	WSS-PRI						
110		750 kW	250,000	$18,409.75	$21,222.00	$2,812.25	15.3%
111		750 kW	300,000	$22,075.75	$24,062.00	$1,986.25	9.0%
112		750 kW	400,000	$29,407.75	$29,742.00	$334.25	1.1%
	WSS-SUB						
113		750 kW	250,000	$16,122.25	$18,606.50	$2,484.25	15.4%
114		750 kW	300,000	$19,330.75	$21,408.50	$2,077.75	10.7%
115		750 kW	400,000	$25,747.75	$27,012.50	$1,264.75	4.9%
	WSS-TOD-SEC						
116	On-Peak 30%	--	100,000	$7,470.80	$8,075.80	$605.00	8.1%
117	Off-Peak 70%	--	200,000	$14,923.40	$16,124.60	$1,201.20	8.0%
118							
	IS						
119		--	1,000	$213.60	$215.13	$1.53	0.7%
120		--	2,500	$533.98	$537.84	$3.86	0.7%
121		--	4,000	$854.35	$860.54	$6.19	0.7%
	EHG						
122		25 kW	3,500	$509.16	$574.21	$65.05	12.8%
123		25 kW	4,000	$579.81	$617.12	$37.31	6.4%
124		25 kW	4,500	$650.47	$660.05	$9.58	1.5%