City Of South Bend Exhibit 5
Cause No. 45235

STATE OF INDIANA

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**

FILED
September 17, 2019
INDIANA UTILITY
REGULATORY COMMISSION

INTERVENOR CITY OF SOUTH BEND EXHIBIT 5
CROSS ANSWERING TESTIMONY OF WILLIAM STEVEN SEELYE

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony on August 20th, 2019.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address class cost of service and revenue allocation issues raised in the direct testimony of the following witnesses: Glenn A. Watkins on behalf of the Office of the Utility Consumer Council ("OUCC"); Jonathan Wallach on behalf of the Citizens Action Coalition of Indiana and Indiana Community Action Association ("CAC and INCAA"); and Nicholas Phillips, Jr on behalf of the Indiana Michigan Industrial Group ("I&M Industrial Group").

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Electric Cost of Service Study, (III) Allocation of the I&M's Revenue Increase.

II. ELECTRIC COST OF SERVICE STUDY

A. OVERVIEW OF THE POSITIONS OF OTHER INTERVENING PARTIES

Q. What is the purpose of a class cost of service study in developing rates for an electric utility?

A. The general purpose of a class cost of service study is to determine the cost of providing service for each of the major customer classes served by a utility for use in developing rates. As explained in the National Association of Regulatory Utility Commissioners

("NARUC") *Electric Utility Cost Allocation Manual*:

> Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. (National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual* at p. 12.)

More specifically, a cost of service study is used to attribute costs to each rate class based on how customers in the class cause costs to be incurred. A cost of service study can also be used to identify costs that should be recovered through the various components of the utility's rates such as the basic service or customer charge, energy charge, and demand charge. In developing South Bend's recommended allocation of the revenue increase to the rate classes, I relied on I&M's cost of service study adjusted to reflect a 3 CP methodology for allocating fixed production, transmission and certain distribution costs and a zero-intercept methodology for classifying distribution costs as customer- or demand-related. My recommendations are based on an objective evaluation of cost causation. Therefore, my recommendations should not be construed as implying positions that I did not explicitly set forth in my direct testimony or in this cross-answering testimony. For example, I have not taken a position on the appropriate level of the residential customer charge, other than to observe that I&M's own cost of service study does not support its proposed customer charge. If the Commission determines that I&M's cost of service study is reasonable, then I&M's proposed customer charges cannot be justified.

Q. Is there general agreement among the intervenor witnesses on the purpose of a class cost of service study?

A. Yes, I believe that there is. The cost of service witnesses in this proceeding seem to acknowledge, perhaps by varying degrees, that the cost of service should be recognized in setting rates. However, the witnesses have different preferences for the methodology or methodologies that should be considered. In this proceeding, Indiana Michigan Power Company ("I&M") submitted a cost of service study using a six Coincident Peak ("6 CP") methodology for allocating fixed production and transmission costs.

The OUCC's witness Mr. Watkins submitted three different versions of the I&M cost of service study using alternative methodologies for allocating fixed production costs: (1) Peak and Average ("P&A") methodology; (2) the Base Intermediate and Peak ("BIP") methodology and; (3) a twelve Coincident Peak ("12 CP") methodology. The P&A and BIP methodologies allocate a portion of fixed production costs on the basis of the amount of energy used by each class as opposed to peak demands. The 12 CP methodology allocates fixed production costs on the basis of peak demand and uses the highest peak from each month of the test period to represent each of the twelve peaks utilized to allocate fixed production costs. Mr. Watkins does not take a preferred position regarding which methodology he would propose in this case. I do not consider OUCC's cost of service methodologies to be objective, or reasonable reflections of I&M's costs that are incurred to provide reliable and adequate electric service to meet peak demands. Rather, they seem slanted to favor those classes that heavily support or drive peak demands. In what can only be described as ***relativism***, the OUCC witness uses the average results from three dissimilar alternative cost of service methodologies for allocating production fixed costs as a basis for his proposal because as he states:

> As indicated earlier, there is no single, or absolute, correct method to allocate joint generation costs. While some methods are superior to others,

> the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility. (*Id*., at pages 23-24.)

CAC's witness Mr. Wallach proposes an alternative methodology for allocating fixed production costs known as the Equivalent Peaker ("EP") methodology.

I&M Industrial Group proposes using either a 4 CP Summer or PJM 5 CP Peak Load Contribution ("PLC") alternative methodology for allocating fixed production costs. The 4 CP methodology uses the 4 summer-month Coincident Peaks from June to September which represent the highest forecasted peaks during the I&M test period. The PJM 5 CP PLC methodology uses the five highest PLC peak hours as determined by PJM.

Q. Please briefly describe the methodology the City of South Bend proposed to allocate fixed production costs.

A. The City of South Bend proposed allocating fixed production and transmission costs on the basis of a 3 CP methodology using the summer months of June, July, and August.

B. OUCC'S POSITIONS ON CLASS COST OF SERVICE

Q. Please address the specific criticisms of the 6 CP methodology made by the OUCC's witness.

A. The OUCC's witness, Mr. Watkins, states:

> Cost allocation methods that only consider peak loads or demands such as the 1CP, 4CP, and 6CP do not reasonably reflect cost causation for electric utilities because these methods totally ignore the type and level of investments made to provide generation service. When generation cost responsibility is assigned to rate classes only on a few hours of peak demand, there is an explicit assumption that there is a direct and proportional correlation between peak load (for a few hours) and the utility's <u>total</u> investment in its portfolio of generating assets. Such is certainly not the case with utilities such as I&M wherein the portfolio of generation assets are predominately comprised of nuclear and coal units installed coupled with run of river hydro facilities that provide power throughout the year. (Watkins testimony at page 14, lines 17-26.)

Mr. Watkins goes on to say:

> Peak responsibility methods such as the 1-CP, 4-CP, and 6-CP totally ignore the planning criteria used by utilities to minimize the total cost of providing service, do not reflect the utilization of generating assets throughout the year, and therefore, do not reflect in any way how capital costs are incurred; i.e. do not reflect cost causation. (*Id*., at page 15, lines 8-11.)

Q. Do you agree with Mr. Watkin's assessment of the "Peak responsibility methods" such as 6 CP?

A. No. Mr. Watkins argues that generation resources should be allocated to the customer classes based on how the generation resources are ***utilized*****,** rather than on how those generation resources are planned and built based on the amount of ***capacity required*** to serve customers. As discussed in my direct testimony, I&M must plan and size its generating resources to meet to meet its peak demand, not how those facilities are utilized. Generation, transmission and distribution facilities are designed and built to handle the maximum flow of electricity during periods of when customers require the most demand. If this was not done, the electric system would be inadequate, would fail to operate properly or simply fail. Undersized and underbuilt facilities would fail to meet customers' needs.

I&M is a utility with an obligation to serve its native customers. That means it has a mandatory requirement to provide its customers with affordable and reliable electric service. The obligation to serve means that when customers flip the switch a light will turn on and or when a thermostat is engaged an air-conditioning system will operate. Thus, to ensure continuous service, the utility must size its capacity based on the projected system peak demand plus a margin to provide for contingencies such as forced outages, unexpected severe weather or load forecast error. If I&M were to size its generation capacity to meet average demand (i.e., utilization), it is likely that the utility could not provide continuous service because during times of high demand, it would not have adequate resources to serve those demands.

Additionally, an investment that is built to serve on-peak demand is also available to serve off-peak demand. In other words, off-peak usage is essentially a *bi-product* of on peak usage. A utility does not need to install additional capacity to meet off-peak demands because the capacity installed to meet peak demands is more than adequate to serve off-peak demands.

Q. Please briefly describe the Peak and Average methodology.

A. The Peak and Average ("P&A") methodology attempts to assign fixed production costs partially on the basis of class contributions to peak loads and partially on the basis of average demand. With the P&A methodology, the portion of plant allocated on class energy is determined based on the ratio of the utility's average demand to its peak demand (i.e. total retail load factor). The residual portion is allocated based on class coincident peak demands.

Q. What are the results of the OUCC's alternative cost of service study utilizing the P&A methodology for allocation of fixed production costs?

A. To determine the "average" portion of fixed production costs, the OUCC's alternative P&A methodology calculates I&M's forecasted test year Indiana retail load factor. This results in a 62.24% allocation of fixed production costs of the basis of average demand or energy. Thus, the P&A methodology allocates the majority of fixed production costs based purely on the average *utilization* of I&M's generation resources to serve the load. The remaining 37.76% of fixed production costs are allocated based on each class's contribution to I&M's forecasted annual peak which occurs in June 2020.

Q. Do you agree with the P&A methodology proposed as one of the alternative methodologies by the OUCC's witness?

No. The P&A methodology allocates the majority of fixed production costs on the basis of energy which has nothing to do with the capacity requirements of customers which drives the decisions I&M makes regarding the size of its capacity resources. The P&A methodology therefore does not adequately reflect the capacity installed to serve the class load and places a greater emphasis on the off peak utilization of the generation plants to provide service to customers. The P&A methodology favors rate classes that have high on-peak demands (kW) but low amounts of energy (kWh) consumption and penalizes rate classes that have high energy usage (kWh) but lower relative peak demands (kW). In other words, the P&A methodology penalizes classes that have high load factors, e.g., more constant load patterns. (*Load factor* is the ratio of average demand to peak demand.) The P&A methodology does not assign costs in a manner that reflects how and why generation capacity was designed and installed, both of which are driven by system peak demand, not consumption of energy. The P&A methodology is a good example of a study that adheres to the perspective that the majority of fixed production costs should be allocated on the basis of ***utilization of service*** rather than ***cost of service***. Consequently, the P&A methodology does not provide useful information concerning *cost of service*, but instead incorporates a subjective view about *fairness* by rewarding customer classes that use power predominantly during peak periods and by penalizing customer classes that improve their load factors by using more energy during off-peak peaks.

Q. Why is it problematic to consider the utilization of the power plants in allocating costs?

A. The *utilization* of the power plant has little or no bearing on I&M's fixed production costs that have been designed and installed to ensure service to customers during peak demand periods. To demonstrate this, consider the situation where a customer or customer class increases its off-peak usage of electric energy. Increasing usage during the off-peak period will not increase the Company's fixed production costs. Increases in off-peak usage can be served with existing generating resources and will not result in the need for additional generation capacity or off system purchases. If anything, increased utilization during off-peak periods will lower generation costs over the long run because customers are more efficiently utilizing the generating resources installed to meet their capacity needs. This is not the case with increases in demand during on-peak periods. Because utilities install generation capacity to meet maximum on-peak demands, increases in on-peak demands will ultimately result in additional capacity and in additional fixed costs. Therefore, it is inappropriate to penalize customers who utilize the existing generating resources more efficiently if the utilization occurs outside of the peak periods because it does not result in any additional fixed production costs to be incurred. Off-peak use of electric capacity does not require the utility to install additional capacity to serve the load. I&M is planning to add significant generation capacity additions over the next two decades. None of those additions are the result of off-peak users such as streetlighting customers.

Because the OUCC's P&A methodology allocates a significant portion of fixed costs to the off-peak utilization of the Company's generation resources, the methodology fails to accurately reflect actual cost of service.

Q. Is the P&A methodology particularly punitive to streetlighting customers?

A. Yes, absolutely. Street lighting service is utilized during nighttime periods, which are predominately off-peak, particularly during I&M's summer peak months. It is never necessary for I&M to install additional generation or transmission capacity to serve streetlighting customers. Any capacity needed to serve streetlights is essentially a bi-product of capacity needed to service on-peak customers. By allocating over 60% of generation and transmission fixed costs and a large portion of distribution demand costs on the basis of energy, the P&A methodology ***severely punishes*** streetlighting customers who do not contribute to I&M's peak summer demands and who do not ever cause generation and transmission capacity to be installed. The P&A methodology is particularly problematic and counterproductive for municipal street lighting customers who are struggling to manage restricted financial resources while maintaining adequate municipal public services in their communities.

Q. **Mr. Watkin's mentions that due to I&M being a net seller of energy in the PJM energy market, that utilization of those resources must be considered in the allocation of production fixed costs. Do you agree?**

A. No. The OUCC's witness states that:

> …as it relates to use of the system, I&M is a net off-system seller of electricity the majority of the year. That is, even though I&M purchases power for many hours of the year, during most of these hours, I&M is a net off-system seller; i.e., its off-system sales are greater than its power purchases. As points of comparison, I&M is a net seller 7,332 hours of the year (84% of the time). Perhaps more importantly is the fact that I&M tends to be a net seller even during system peak load hours. As illustrations, during 2018, I&M was a net seller during both the winter peak and summer peak hours. Furthermore, during the 25 highest system peak load hours in 2018, I&M was a net seller during 23 of these hours. The fact that I&M is a net off-system seller of electricity the vast majority of the year as well as during peak periods is important because I&M's generation is based predominately on low energy cost base load units which enables the Company to make off-system sales over and above its internal load obligations. (*Id.*, at page 21, lines 9-21.)

The fact that I&M is a net seller for the majority of the year is a positive for I&M's native customers. Whenever I&M generation resources are dispatched into the PJM market, it signals that I&M's marginal cost of producing energy is equal to or below the market cost of providing energy. This means that if market revenues are higher than I&M's marginal cost of energy (i.e. fuel plus variable O&M costs), that any off-system sale made during periods in which that capacity is not needed by native load contributes towards cost recovery on assets being paid by I&M native customers in the form of a credit on their bill for off system sales margins. Therefore, these off-system sales offset a portion of the costs being paid by I&M customers and without these sales, rates charged to native customers would almost certainly be higher than they're proposing in this proceeding. The simple fact that I&M is a net seller into the PJM market is not justification for allocating fixed production costs on the basis of energy. These off-system sales represent a more efficient utilization of the assets dispatched by I&M and almost certainly reduce the overall cost of service to I&M customers which is not a reasonable justification for allocating a large portion of the cost of generation facilities on the basis of utilization or energy.

Q. OUCC also relied on BIP. Please briefly describe the BIP methodology.

A. "BIP" refers to Base-Intermediate-Peak fixed production costs. The BIP method evaluates a utility's fleet of generating resources and classifies each resource as either "baseload" resources which contribute to baseload energy needs the majority of hours during the year, intermediate resources which sometimes contribute to shoulder peak periods and during maintenance periods for baseload resources and are utilized moderately over the course of the year, and peaking resources which are only dispatched during peak periods generally occurring during the summer and winter months. The classification of each generating resource is typically based on each unit's capacity factor which is the ratio of its annual overall energy output compared to its maximum nameplate capacity being produced all 8,760 hours of the year. As such, the BIP methodology generally allocates large coal and nuclear units as resources that contribute to the "Base" period whose costs are typically allocated based on average demand; i.e. energy. Intermediate and Peak resources, such as Combined-Cycle Gas turbines and Simple Cycle Combustion turbines are allocated based on coincident peak demand for their respective portions of fixed production costs.

Q. Is there a problem with relying on the BIP?

A. Yes. The problem with the BIP methodology is that when a utility's generating fleet is made up primarily of base load generating resources, like I&M's portfolio of resources, it assigns the vast majority of cost responsibility for fixed production costs to the Base period which is allocated based on average demand. It grossly understates that those base load resources are critical to meeting peak system demands. In reviewing Mr. Watkin's cost of service study utilizing the BIP methodology, approximately 82.78% of the fixed production plant was allocated based on energy, which is an even higher percentage of allocation based on utilization than the P&A methodology. With this approach, virtually all I&M's generation assets are assigned as base period costs, meaning they are allocated based on their <u>*utilization*</u> and allocated based on kWh despite significant seasonal variations in the Company's load including three dramatic summer peak months, as outlined in my direct testimony.

Q. Does the application of the BIP Methodology create the same problems as the P&A methodology?

A. Yes, but even more so. The fact that the BIP methodology allocates the majority of fixed production and transmission costs on the basis of energy results in the same issues that are described above regarding the P&A methodology. In fact, the BIP methodology allocates over 20% more fixed production costs on the basis of energy than that P&A methodology. This would penalize high load factor, efficient users of the generation and transmission capacity installed by I&M to meet peak system demand to an even greater extent than the P&A methodology. The BIP methodology would also send a price signal that penalizes consumption during the off-peak periods, the periods that do not contribute towards additional fixed cost capital expenditures.

Q. Are you aware of any regulatory commission that has adopted the BIP methodology proposed by Mr. Watkins?

A. No.

Q. OUCC also relied on 12 CP. Please briefly describe the 12 CP methodology.

A. The 12 CP methodology uses the sum of the 12 monthly peak hours for the forecast period to allocate fixed production costs. Because the 12 CP methodology does not utilize energy as a factor in determining the amount of plant allocated to the customer classes, the 12 CP is an altogether different approach than the other two methodologies considered by Mr. Watkins.

Q. Do you agree with the use of the 12 CP methodology proposed as an alternative by the OUCC?

A. No. While I generally agree with the use of a CP methodology, and the 12 CP methodology is certainly more reasonable as a basis for allocating fixed production costs compared the extreme P&A and BIP alternatives put forth by the OUCC, more targeted, cost driven versions of the CP methodology are more appropriate for I&M. Due to the wide variation in I&M's system peak demands over the course of the year, the 12 CP methodology places an equal weighting on each monthly peak demand when in reality I&M plans and builds its generating facilities to meet the largest of its peak demands, which occur in the Summer months. As I previously pointed out, I&M's three peak summer months are far higher than the peaks of any other months. For this reason, the 3 CP proposal put forth in my direct testimony, or the 4 CP and PJM 5 CP methodologies proposed by the I&M Industrial Group, are much more appropriate and reflect more accurate costs for I&M. A 12 CP methodology has the effect of diluting the allocation of I&M's investment in production facilities which are primarily designed to meet a summer peak demand.

Q. The OUCC's witness also proposes to allocate Transmission fixed costs on the basis of a 12CP. Do you agree with this alternative?

A. Since I&M's transmission facilities must be planned and sized to meet the highest demand placed on the system, the same argument applies for these facilities as it does for production facilities. If transmission facilities are undersized, it would be more likely that during peak demand periods the I&M system would be subject to failure. Transmission poles, towers, and conductor require adequate demand carrying capability and height to safely and reliably meet the highest demands of I&M's customers. Therefore, those facilities should also be allocated based on the summer peak demands which they are engineered to meet. For this reason, a more targeted CP methodology, such as a 3CP, 4CP, or PJM 5CP should be used to allocate transmission fixed costs.

C. CAC POSITION ON CLASS COST OF SERVICE

Q. Please address CAC's witness Mr. Wallach's specific criticisms of the 6 CP methodology.

A. Similar to the OUCC, CAC witness Wallach criticizes I&M's use of the 6 CP methodology. Specifically, Mr. Wallach states that "the Company's CCOSS inappropriately classifies all production plant costs as demand-related, as if such costs were incurred solely for the purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy requirements". (Wallach direct testimony page 12, lines 11-14.) He goes on to state that "baseload or intermediate plants costs *in excess of peaking plant costs* (so-called "capitalized energy costs) should be classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements". (Wallach direct testimony page 13, lines 16-20.) In light of these arguments, the CAC witness proposes the use of the Equivalent Peaker methodology for allocating production fixed costs.

Q. Do you agree with Mr. Wallach's assessment?

A. No. As discussed above, I&M plans and constructs its production facilities based on its native customer's peak demands, not its energy requirements. For the same reasons described above, Mr. Wallach's allocation of production fixed costs on the basis of utilization are at odds with how I&M incurs those costs.

Q. Please briefly describe the Equivalent Peaker methodology.

A. The Equivalent Peaker ("EP") methodology attempts to split fixed production costs between demand-related and energy-related costs by comparing I&M's embedded costs of capacity to the average cost of new peaking facilities. The EP methodology classifies all peaking facility costs as demand-related while analyzing baseload and intermediate resources to determine proportionate classifications of demand and energy. This is done based on the in-service dates of the existing facilities and a calculated installed cost of all units in the dollars of the installed date and classifies the peaking facility costs as demand-related. The remaining costs are classified as energy-related.

Q. What are the results of the CAC's alternative cost of service study utilizing the EP methodology for allocation of fixed production costs?

A. The CAC's alternative cost of service study results in 69% allocation of fixed production costs of the basis of average demand or energy. Thus, the EP methodology allocates the majority of fixed production costs based purely on the average *utilization* of I&M's generation resources to serve the load. The remaining 31% of fixed production costs are allocated on the basis of each class's contribution to I&M's forecasted annual peak which occurs in June 2020.

Q. Do you agree with the EP methodology proposed by the CAC's witness?

No. The EP methodology allocates the majority of fixed production costs on the basis of energy, which has nothing to do with the capacity requirements of customers that drives the decisions I&M makes regarding its capacity resources. The EP methodology therefore does not adequately reflect the capacity installed to serve the class load and places a greater emphasis on the utilization of the generation plants to provide service to customers. The EP methodology favors rate classes that have high peak demands (kW) but low amounts of energy (kWh) and penalizes rate classes that have high energy usage (kWh) but lower relative demands (kW).

Additionally, the method in which the EP methodology determines how much of the embedded production costs has been incurred is based on the cost of a new, marginal capacity resource. This effectively allocates fixed production costs on the basis of marginal cost, which are two different evaluations of cost with two very different applications.

Marginal utility costs are based on some additional increment of demand or energy. Marginal energy costs represent the cost for a utility to produce an additional kWh of energy, which is based on its fuel and variable O&M costs and the diversity of its generating fleet. Marginal demand costs represent the cost for a utility to produce an additional increment of demand, generally measured in Megawatts ("MW"). A utility's marginal demand costs are dependent on how much excess capacity it currently has available. If a utility has excess capacity available to serve the next MW of demand, the utility's marginal demand costs are effectively zero. If the utility does not have excess capacity available to serve the next MW of demand, then its marginal demand cost is substantial and depends on the type of new capacity resource chosen to determine that cost. In the case of the EP methodology, Mr. Wallach proposes to use the average installed cost of simple-cycle Combustion Turbines installed in Indiana from 2017 to 2018.

This approach effectively mixes the two methods of evaluating utility costs in an effort to calculate how "embedded" demand costs should be allocated based on a calculation of "marginal" demand. The methodology then assumes that the remaining installed production costs are incurred due to the energy requirements of its customers which is a poor assumption and should therefore be rejected.

D. I&M INDUSTRIAL GROUP POSITION ON CLASS COST OF SERVICE

Q. Please summarize the I&M Industrial Group's criticisms of I&M's 6 CP methodology for allocating fixed production and transmission costs.

A. The I&M Industrial Group witness Phillips has essentially the same reservations as I have regarding I&M's proposed 6 CP methodology for allocating fixed production and transmission costs in its class cost of service study. Mr. Phillips states:

> Significant changes in I&M's operations within recent years warrant a change from the 6CP methodology to the 5CP PLC methodology. The 4 summer peak method is also more reflective of, historical, current, and future I&M data and operations then the 6CP method proposed by the Company.[1]

Mr. Phillips goes on to recommend either the 5 CP PLC method employed by PJM or a 4 CP method utilizing the summer months of June through September.

Q. Do you disagree with Mr. Phillips' assessment?

A. No. As discussed in my direct testimony, an allocation based on a 4 Summer CP methodology or a 5 CP methodology would more accurately reflect cost causation on I&M's system than its proposed 6 CP methodology that includes lower peak demands from the winter months.

Q. Does Mr. Phillips have concerns regarding the allocation of fixed distribution costs in the I&M cost of service study?

A. Yes. The I&M Industrial Group expresses similar concerns with I&M's failure to appropriately allocate distribution fixed costs between customer-related and demand-related costs as I did in my direct testimony. I&M proposed to allocate fixed distribution costs in plant accounts 364 through 368 as 100% demand-related costs which does not reflect cost causation.

1 Phillips, Jr Direct testimony page 12, lines 12-15.

Q. How does Mr. Phillips propose to allocate fixed distribution costs?

A. Mr. Phillips proposes a Minimum System methodology to split distribution related fixed costs between demand-related and customer-related costs.

Q. Is the Minimum System methodology an approved methodology for determining the split of distribution fixed costs between demand and customer-related components?

A. Yes. The Minimum System is one of two methodologies for the allocation of distribution plant approved by NARUC in its Electric Utility Cost Allocation Manual along with the Zero Intercept methodology.

Q. Do you agree with Mr. Phillips Jr's Minimum System alternative proposal of a Minimum System allocation for distribution fixed costs?

A. While I agree that the Minimum System methodology for allocating distribution related fixed costs is certainly better than I&M's proposed methodology of allocating all distribution costs on the basis of demand, I prefer the Zero Intercept methodology when the appropriate data is available due to its less subjective assumptions and more appropriate calculation of the zero-demand capability of the distribution system to determine the customer-related portion of distribution costs.

III. ALLOCATION OF I&M'S REVENUE INCREASE

Q. Do you agree with the allocation of the revenue increase proposed by the OUCC?

A. No. The OUCC's proposed allocation of the revenue increase is based on the three alternative methodologies described above which are flawed. The OUCC's proposed methodologies in the cost of service studies result in penalizing more efficient users of capacity and those who use capacity during off-peak periods. The OUCC then proposes to lower increases to less efficient and more coincident users of I&M's capacity and makes no effort to reduce subsidies currently in effect.

Q. Do you agree with the allocation of the revenue increase proposed by the CAC?

A. No. The CAC's proposed allocation of the revenue increase is also based on its own flawed alternative cost of service study. While I don't agree with the CAC's cost of service results, I give them credit that they made a concerted effort to reduce the subsidies shown based on their results and only allocated increases to those classes which showed a Rate of Return below the over I&M system return. This is a substantial improvement over the OUCC's proposed revenue allocation but is still very inadequate and fails to take necessary and meaningful steps in eliminating subsidies currently in place.

Q. Do you agree with the allocation of the revenue increase proposed by the I&M Industrial Group?

A. I agree that the I&M Industrial Group's allocation methodologies better reflect cost causation than the one proposed by the Company, but still believe a more aggressive subsidy reduction is warranted than the proposed 25% reduction given the large variation in class rates of return. I also disagree with imposing a restriction on rate decreases in reducing subsidies by 25%. The rate of return for Street Lighting is so high that the Street Lighting rates must be reduced. As South Bend's case in chief testimony describes, streetlights are critical public safety services that need to be expanded in number and converted to energy efficient LEDs. Not giving streetlights the rate reduction my objective COSS suggests prevents the full expansion and energy efficiency conversion of streetlights. South Bend cannot afford to be over charged for streetlights and notably the total streetlight class revenue of $5.4 million is only 0.1% of I&M's total revenue of $4.9

billion. Municipal streetlight customers need and deserve the rate reduction I have suggested. Otherwise, the large subsidies currently being paid be municipal streetlighting customers will continue unabated and the vital public service they provide will continue to be diminished and limited.

Q. Is it reasonable that I&M's streetlighting rates should be reduced when most other rate classes would be increased?

A. Yes. I&M is earning an excessive rate of return on streetlighting service. South Bend is proposing to decrease I&M's streetlighting revenue from its current level by approximately $934,000. To put this in perspective, OUCC is proposing in this proceeding to reduce I&M's proposed revenue increase from $174 million as proposed by I&M to approximately $1.7 million as proposed by OUCC. (See Direct Testimony of OUCC witness Michael D. Eckert, at page 8.) Should OUCC's proposed revenue requirement be approved by the Commission, reducing the subsidies to the Street Lighting classes as proposed by South Bend would have minimal impact on other rate classes due to OUCC's proposed revenue increase is approximately 1% of I&M proposal. In fact, under OUCC's revenue requirement complete elimination of the subsidy currently being provided by Street Lighting should be strongly considered. Considering the extraordinarily high rate of return that I&M is currently earning on streetlighting service, South Bend's proposed reduction in streetlighting revenue is not out of line.

Q. Does this conclude your cross answering testimony?

A. Yes.

VERIFICATION

I affirm under the penalties of perjury that the foregoing Cross Answering Testimony is to the best of my knowledge and belief true and accurate.

____

William Steven Seelye,

Dated: September 16, 2019

CERTIFICATE OF SERVICE

I certify the forgoing was electronically served on September 17, 2019, upon the following:

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