

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

JOINT MUNICIPAL INTERVENORS' EXCEPTIONS TO I&M'S PROPOSED ORDER

The City of Fort Wayne, the City of Marion, and Marion Municipal Utilities,  
(collectively the "Joint Municipal Intervenors"), by counsel, respectfully submit these  
Exceptions to Indiana Michigan Power Company's ("I&M's") Proposed Order, filed November  
11, 2019. **The Joint Municipal Intervenors also adopt the summaries of the respective  
witnesses' testimony (in lieu of those provided by I&M) included in the Exceptions to  
I&M's Proposed Orders filed today by the Office of the Utility Consumer Counselor and  
other Intervenors.** Counsel for Marion is authorized to make this filing jointly on behalf of the  
City of Fort Wayne.

Respectfully submitted,



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The undersigned hereby certifies that a copy of the foregoing was served by hand delivery, electronic transmission or U.S. Mail, first class postage prepaid, this 3rd day of December, 2019.

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**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

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AND (7) NEW SCHEDULES OF RATES, )  
RULES AND REGULATIONS. )**

**ORDER OF THE COMMISSION**

**Presiding Officers:**

**David L. Ober, Commissioner**

**Carol Sparks Drake, Senior Administrative Law Judge**

On May 14, 2019, Indiana Michigan Power Company (“Petitioner,” “Company” or “I&M”) filed a Petition with the Indiana Utility Regulatory Commission (“IURC” or “Commission”) seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below.<sup>1</sup> The Petition included a request for administrative notice. On May 14, 2019, Petitioner also filed its Case-in-Chief, workpapers and information required by the minimum standard filing requirements (“MSFRs”) set forth at 170 Ind. Admin. Code (“IAC”) 1-5-1 *et seq.* The following witnesses filed testimony and exhibits:

- Toby L. Thomas, President and Chief Operating Officer for I&M
- Andrew J. Williamson, Director of Regulatory Services for I&M
- David A. Lucas, Vice President Finance and Customer Experience for I&M
- Nancy A. Heimberger, Financial Analyst Senior Staff in Corporate Planning and Budgeting for American Electric Power Service Corporation (“AEPSC”)
- David S. Isaacson, Vice President of Distribution Operations for I&M
- Q. Shane Lies, Site Vice President of the Donald C. Cook Nuclear Plant for I&M

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<sup>1</sup> On April 10, 2019, I&M provided its notice of intent to file a rate case in accordance with the Commission’s General Administrative Order 2013-5.

- Timothy C. Kerns, Managing Director – Generating Assets for I&M
- Kamran Ali, Managing Director of Transmission Planning for AEPSC
- Jason A. Cash, Accounting Senior Manager in Corporate Accounting for AEPSC
- Aaron L. Hill, Director of Trusts and Investments for AEPSC
- Roderick Knight, Decommissioning Manager for TLG Services, Inc.
- Michael N. Kelly, Manager – Taxes of Tax Accounting and Regulatory Support for AEPSC
- Robert B. Hevert, Partner of ScottMadden, Inc.
- Franz D. Messner, Managing Director of Corporate Finance for AEPSC
- Jeffrey W. Lehman, Electric Transportation Program Manager for AEPSC
- Chad M. Burnett, Director of Economic Forecasting for AEPSC
- Tyler H. Ross, Director of Regulatory Accounting Services for AEPSC
- Jennifer C. Duncan, Regulatory Consultant Principal in the Regulated Pricing and Analysis Department for AEPSC
- Michael M. Spaeth, Senior Regulatory Consultant in the Regulated Services Department for AEPSC
- Matthew W. Nollenberger, Manager, Regulated Pricing and Analysis for AEPSC
- Kurt C. Cooper, Regulatory Consultant Principal for I&M

On June 26, 2019, the Commission issued a Prehearing Conference Order, which established a procedural schedule and other requirements for this Cause.

Petitions to Intervene were filed by I&M Industrial Group, an ad hoc group of the following customers: Air Products, General Motors LLC, I/N Tek L.P., Marathon Petroleum Company LP, Messer LLC, Praxair, Inc., and University of Notre Dame du Lac (“IG” or “Industrial Group”); the Kroger Company (“Kroger”); Steel Dynamics, Inc. (“SDI”); Wal-Mart, Inc. (“Walmart”); Citizens Action Coalition of Indiana, Inc. (“CAC”), Indiana Community Action Association (“INCAA”), (collectively “CAC-INCAA”); City of Fort Wayne, Indiana, City of Marion, Indiana and Marion Municipal Utilities (collectively, “Marion” and, with Fort Wayne, collectively the “Joint Municipal Group”); City of South Bend, Indiana (“South Bend”); 39 North Conservancy District (“39 North”); Wabash Valley Power Association, Inc.; and City of Auburn Electric Department (“Auburn”).

These petitions were granted without objection. Alliance Coal, LLC (“Alliance”) and the Indiana Coal Council, Inc. (“ICC”) also filed Petitions to Intervene, which petitions were subsequently granted over I&M’s objection. The Indiana Office of Utility Consumer Counselor (“OUCC”) also participated as a party.<sup>2</sup>

Public field hearings were held on July 11, 2019 in the City of South Bend, on July 15, 2019 in the City of Muncie, and on July 16, 2019 in the City of Fort Wayne, the largest municipality in Petitioner’s Indiana service area. At the field hearings, members of the public were afforded the opportunity to make statements to the Commission.

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<sup>2</sup> While the International Brotherhood of Electrical Workers Local 1392 (“IBEW”) was granted leave to intervene, the IBEW subsequently sought leave to withdraw from this proceeding, which request was granted by Docket Entry dated August 19, 2019.

On August 20, 2019, the OUCC and certain Intervenor filed their respective cases-in-chief. The OUCC provided testimony and exhibits from the following witnesses:

- Lauren M. Aguilar, Utility Analyst
- Anthony A Alvarez, Utility Analyst
- Cynthia M. Armstrong, Senior Utility Analyst
- Wes R. Blakley, Senior Utility Analyst
- Michael D. Eckert, Assistant Director of the OUCC Electric Division
- Michael Gahimer, Senior Utility Analyst
- David J. Garrett, Managing Member of Resolve Utility Consulting, PLLC
- Mark E. Garrett, President of Garrett Group Consulting, Inc.
- John E. Haselden, Senior Utility Analyst
- Kaleb G. Lantrip, Utility Analyst
- Margaret A. Stull, Chief Technical Advisor in the Water/Wastewater Division
- Glenn A. Watkins, President and Senior Economist of Technical Associates, Inc.

The I&M Industrial Group provided testimony and exhibits from the following witnesses:

- Brian C. Andrews, Senior Consultant with Brubaker & Associates, Inc. (“Brubaker”)
- James R. Dauphinais, Consultant and a Managing Principal with Brubaker
- Michael P. Gorman, Consultant and a Managing Principal with Brubaker
- Nicholas Phillips, Jr., Consultant and a Managing Principal with Brubaker

Kroger provided testimony and exhibits from the following witness:

- Justin Bieber, Senior Consultant for Energy Strategies, LLC

Walmart provided testimony and exhibits from the following witness:

- Steve W. Chriss, Director, Energy Services for Walmart

The CAC-INCAA provided testimony and exhibits from the following witnesses:

- Kerwin L. Olson, Executive Director of CAC
- Jonathan F. Wallach, Vice President of Resource Insight, Inc.

The Joint Municipal Group provided testimony and exhibits from the following witnesses:<sup>3</sup>

- Constance T. Cannady, Executive Consultant at NewGen Strategies and Solutions, LLC.
- Douglas J. Fasick, Senior Program Manager, Utilities Energy Engineering and Sustainability Services for the City Utilities Division for City of Fort Wayne, Indiana
- Joseph A. Mancinelli, President and Chief Executive Officer of NewGen Strategies

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<sup>3</sup> The Joint Municipal Group also submitted a Motion for Administrative Notice with its case-in-chief.

and Solutions, LLC.

South Bend provided testimony from the following witnesses:

- Therese Dorau, Director of Sustainability for the City of South Bend
- Theodore Sommer, Partner with LWG CPAs and Advisors
- William Steven Seelye, managing partner for The Prime Group, LLC

39 North provided testimony from the following witness:

- Reed W. Cearley, special utility consultant for 39 North

Auburn provide testimony from the following witness:

- Edward T. Rutter, Manager with LWG CPAs and Advisors

ICC provided testimony from the following witness:

- Emily S. Medine, Principal for Energy Ventures Analysis, Inc.

On September 17, 2019, the OUCC and Intervenors filed their respective cross-answering testimony. The OUCC provided cross-answering testimony and exhibits from the following witness:

- Glenn A. Watkins

The I&M Industrial Group provided cross-answering testimony and exhibits from the following witness:

- Nicholas Phillips, Jr.

Kroger provided cross-answering testimony and exhibits from the following witness:

- Justin Bieber

CAC-INCAA provided cross-answering testimony and exhibits from the following witness:

- Jonathan F. Wallach

South Bend provided cross-answering testimony from the following witnesses:

- Therese Dorau
- William Steven Seelye

Alliance provided testimony from the following witness:

- Stephen Norfleet, Principle and Senior Project Manager with RMB Consulting and Research, Inc.

I&M subsequently moved to strike the Alliance testimony on the grounds that such testimony was not proper cross-answering testimony and the filing thereof violated the requirements governing the Alliance intervention. I&M's motion was subsequently granted in part by Docket Entry dated September 27, 2019.

On September 17, 2019, I&M filed rebuttal testimony, exhibits and workpapers for the following witnesses:

- Kamran Ali
- Chad M. Burnett
- Andrew R. Carlin, Director of Executive Compensation & Benefits for AEPSC
- Jason A. Cash
- Kurt C. Cooper
- Jennifer C. Duncan
- Robert B. Hevert
- Aaron L. Hill
- David S. Isaacson
- Timothy C. Kerns
- Jeffrey W. Lehman
- Q. Shane Lies
- David A. Lucas
- Matthew W. Nollenberger
- Tyler H. Ross
- Michael M. Spaeth
- Toby L. Thomas
- Andrew J. Williamson

Requests for Administrative Notice filed by I&M and the Joint Municipal Group were granted.

Pursuant to the notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public evidentiary hearing in this Cause commenced on October 7, 2019 and continued on October 10, 11, 15, 16, 17, 21, 22, 23 and 24, 2019. At the evidentiary hearing, the direct, cross-answering, rebuttal and administrative notice materials were offered and admitted into the record. Thereafter, the parties submitted their proposed orders and post-hearing filings in accordance with the post-hearing briefing schedule.

The Commission, based upon the applicable law, the evidence herein, and being duly advised, now finds as follows:

**1. Notice and Jurisdiction.** Due, legal and timely notice of all public hearings in this Cause were given and published as required by law. I&M is a public utility as defined in Ind.



Code § 8-1-2-1(a). Pursuant to Ind. Code §§ 8-1-2-23, 42 and 42.7 the Commission has jurisdiction over I&M's additions and improvements to plant and its rates and charges for retail utility service. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

**2. Petitioner's Organization and Business.** I&M, a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), is a corporation organized and existing under the laws of the State of Indiana, with its principal offices at Indiana Michigan Power Center, Fort Wayne, Indiana. I&M is engaged in, among other things, rendering electric service in the States of Indiana and Michigan. I&M owns and operates plant and equipment within the States of Indiana and Michigan that are in service and used and useful in the generation, transmission, distribution and furnishing of such service to the public. I&M has maintained and continues to maintain its properties in an adequate state of operating condition. Petition, ¶¶ 1-2.

I&M provides electric service to approximately 468,000 retail customers in the following northern and east-central Indiana counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells and Whitley. In Michigan, I&M currently provides retail electric service to approximately 129,000 customers. In addition, I&M serves customers at wholesale in the States of Indiana and Michigan. I&M's electric system is an integrated and interconnected entity that is operated within Indiana and Michigan as a single utility. I&M's transmission system is under the functional control of PJM Interconnection, L.L.C. ("PJM"), a Federal Energy Regulatory Commission ("FERC") approved regional transmission organization ("RTO"), and is used for the provision of open access non-discriminatory transmission service pursuant to PJM's Open Access Transmission Tariff ("OATT") on file with the FERC. As a member of PJM, charges and credits are billed to AEP and allocated to I&M for functional operation of the transmission system, management of the PJM markets including the assurance of a reliable system, and general administration of the RTO. As a PJM member, I&M must also adhere to the federal reliability standards developed and enforced by the North American Electric Reliability Corporation ("NERC"), which is the electric reliability organization certified by the FERC to establish and enforce reliability standards for the bulk power system. ReliabilityFirst ("RF") is one of eight NERC Regional Entities and is responsible for overseeing regional reliability standard development and enforcing compliance. I&M's transmission facilities are wholly located with the RF region. Petition, ¶¶ 3-6.

I&M renders electric service by means of electric production, transmission and distribution plant, as well as general property, equipment and related facilities, including office buildings, service buildings and other property, all of which is used and useful in the generation, purchase, transmission, distribution and furnishing of electric energy for the convenience of the public. I&M's property is classified in accordance with the Uniform System of Accounts ("USOA") as prescribed by FERC and adopted by this Commission. Petition, ¶¶ 7-8.

**3. Existing Rates.** I&M's existing retail rates in Indiana were established pursuant to the Commission's orders in Cause No. 44967 based upon test year operating results for the twelve months ended December 31, 2018. The petition initiating Cause No. 44967 was filed with the Commission on July 26, 2017. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more

than fifteen months has passed between the filing of I&M's Petition in this Cause and I&M's most recent request for a general increase in its basic rates and charges.

4. **Test Year.** As authorized by Ind. Code § 8-1-2-42.7(d)(1) ("Section 42.7"), Petitioner proposed a forward-looking test period using projected data. Consistent with the Prehearing Conference Order, the test year to be used for determining Petitioner's projected operating revenues, expenses, and operating income is the 12-month period ending December 31, 2020. The historical base period is the 12-month period ending December 31, 2018.

5. **I&M's Requested Relief.** In its case-in-chief, I&M requested the Commission to approve an overall annual increase in revenues from its base rates and charges, including rate adjustment mechanisms, in the total amount of approximately \$172 million. I&M proposed to implement the requested revenue increase in three phases: Phase I would increase revenue by approximately \$82.5 million; Phase II would reflect a revenue increase of approximately \$129 million; and Phase III (which would be effective January 1, 2021) would reflect the final revenue increase of approximately \$172 million. As detailed in the Petition and Company's case-in-chief I&M also requested Commission approval of specific accounting and ratemaking relief, including updated depreciation accrual rates and a new rate adjustment mechanism to track advanced metering infrastructure ("AMI") investment. Petition, ¶¶ 21-24.

6. **Opposition, Cross-Answering and Rebuttal.** OUCC and Intervenors presented numerous challenges to the Company's filing, including challenges to rate base, depreciation rates, rate of return, operating and maintenance ("O&M") expenses, rider proposals, cost of service allocation, rate design, and tariffed terms and conditions. The extent to which these parties disagreed with each other was addressed in their respective cross-answering testimony. The Company's disagreement with the OUCC and Intervenors was addressed in I&M's rebuttal evidence.

7. **Petitioner's Rate Base.** I&M's proposed Indiana jurisdictional net original cost rate base at December 31, 2020, is approximately \$4.95 billion.<sup>4</sup> This proposed rate base includes materials and supplies, fuel stock and allowance inventory, deferred gain on the Rockport Unit 2 sale, certain deferred income taxes, regulatory assets and liabilities, and a prepaid pension asset.<sup>5</sup>

As discussed below, the OUCC and/or certain intervenors challenged the continued inclusion of the prepaid pension asset in rate base, the proposed AMI deployment, distribution investment, the enhancement of the Rockport Dry Sorbent Injection ("DSI") system, the Rockport Coal Combustion Residuals ("CCR") Compliance Project, the replacement of the High Pressure Turbine at Rockport Unit 2, the South Bend Solar Project, and the nuclear decommissioning study/rate case expense regulatory asset. We discuss these contested issues below.

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<sup>4</sup> I&M Ex. A-1, 1; Ex. A-6, 1.

<sup>5</sup> In rebuttal, Mr. Kerns testified the \$159.190 million (including allowance for funds used during construction ("AFUDC")) forecasted cost for the Rockport Unit 2 SCR should be adjusted to \$122.676 million (including AFUDC) based on a revised cost estimate presented in Cause No. 44871 ECR-3. Kerns Rebuttal, 9. No party challenged this adjustment and we find it reasonable.

**A. Advanced Metering Infrastructure (“AMI”).**

1. I&M. Mr. Thomas and Mr. Isaacson explained the Test Year infrastructure investment includes the Company’s initial phase of the AMI deployment, which will continue through 2022. Thomas Direct, 19; Isaacson Direct, 28. Mr. Thomas stated the estimated capital cost of the total AMI Project over the three-year period is approximately \$93.6 million. Thomas Direct, 19; see also Williamson Direct, 36.

As discussed by Mr. Thomas, AMI is also referred to as “smart grid” or “smart metering” because it enables two-way communication between the meter and the utility’s central systems. Thomas Direct, 20. He stated this enables the utility to have more accurate information about system operating conditions for operation and planning purposes as well as electricity usage to provide timely information to customers. *Id.* Mr. Thomas added the AMI infrastructure comes with a customer engagement platform that enables the consumer to have better insight into the consumer’s electricity usage and cost. *Id.* Mr. Thomas explained AMI deployment is consistent with the industry and the transition to “smart” technologies enables a fundamental change in the way the Company operates, serving as the necessary foundation upon which the Company will provide more reliable service, improved customer experience and greater efficiency opportunities for I&M’s customers in the future. Thomas Direct, 21-38. Mr. Isaacson elaborated on the operational, reliability and customer benefits of AMI and the Company’s deployment plans. Isaacson, 23, 25, 28-33. Mr. Lucas described how AMI technology will provide access to data that I&M will use to inform and empower customers to make better decisions about their electric consumption habits and manage their monthly budgets and explained the Company’s plan for customer notification and education. Lucas Direct, 17, 38-48.

Mr. Thomas testified the Company’s existing AMR meters are at the point where they are in need of replacing. He said given the age of the existing meters, I&M considered whether to continue to replace failing meters with AMR or move to the next generation of technology. Thomas Direct, 22-23. Mr. Thomas stated in making the decision to move to AMI, the Company recognized that over the past decade AMI technology has matured, its pricing has stabilized and its importance to system reliability has increased. *Id.*, 23. Mr. Thomas stated three years is the period reasonably necessary to efficiently and cost-effectively obtain the necessary resources for the project, install the technology and IT systems and implement the associated consumer education and functionality. *Id.*, 23-24.

2. OUCC. Mr. Alvarez criticized the Company’s AMI proposal and recommended the capital (~\$14 million) and O&M (~\$2.4 million) associated with I&M’s AMI deployment be removed from the Test Year and that the Commission require I&M to prepare a robust cost-benefit analysis and full business case prior to the Commission approving full deployment of AMI in I&M’s Indiana service territory. Alvarez, 2, 4-17, 38. Mr. Alvarez discussed I&M’s AMI deployment plan for Michigan and expressed concern about using that plan for the Indiana deployment. *Id.*, 5-8. Mr. Alvarez stated it does not appear that I&M incorporated the findings, recommendations and operational data from its Smart Meter Pilot Project (“SMPP”) conducted in 2009. *Id.*, 12-14. Mr. Alvarez viewed AMI as an optional upgrade and not necessary to provide service to I&M’s customers. *Id.* Mr. Alvarez pointed to an Ameren Illinois analysis as the type of robust utility cost-benefit analysis he recommended for AMI deployment. *Id.*, 15-16. He also referenced a settled Duke Energy Indiana Transmission,

Distribution, and Storage System Improvement Charge (“TDSIC”) case where AMI deployment savings were quantified. *Id.*, 16 n.42. Mr. Alvarez proposed if the Commission should be inclined to approve I&M’s proposed deployment over the OUCC’s objections, the Commission should approve only the proposed 2020 deployment as a pilot program to be evaluated within the context of a collaborative involving Commission technical staff, the OUCC and interested parties. *Id.*, 17-18.

3. Intervenors. The Joint Municipal Group, South Bend and CAC-INCAA also recommended the Commission disallow the Test Year AMI capital and operating expenses and contended that AMI deployment should not be approved without a detailed cost/benefit analysis. In the alternative, the Joint Municipal Group recommend that the AMI costs be deferred until the actual detailed costs can be evaluated. Cannady Direct, 4, 29-32; Sommer, 5, 33-36; Wallach, 4, 7-10. Mr. Sommer stated he had seen nothing that proves to him that AMR meters are unreliable or will soon fail at an unreasonable rate. Sommer, 34. South Bend’s witnesses contended the proposed costly upgrade to AMI readers is not a prerequisite for successful implementation of the PEV tariff as I&M’s current AMR meters will support the PEV off peak tariff. Dorau, 17; Sommer, 35. Mr. Wallach testified I&M has not provided any evidence in this Cause that the proposed AMI investments are expected to be cost-effective over the life of the investments. Wallach, 8-9. Walmart witness Chriss testified Walmart generally supports the deployment of “smart” metering and appreciated the Company’s efforts in this regard. Chriss, 29. He recommended the Commission make transitioning away from hours-use rates a near-term priority and include a stakeholder process to explore this transition as part of the conditions of approval of AMI deployment in this Cause. Chriss, 5, 29-30.

4. Rebuttal. Mr. Thomas explained why he disagreed that the used and useful standard Indiana uses in a general basic rate case should be replaced with a formulaic assessment of whether the benefits of an infrastructure project exceed the cost thereof. Thomas Rebuttal, 12-13. He also explained why it is difficult to quantify the economic value of the incremental benefits and undertake a meaningful cost-benefit analysis of infrastructure investments such as AMI, particularly where the benefits of moving from manual to automated operations have already been achieved, as is the case for I&M. *Id.*, 13-15. Mr. Thomas testified the 2012 Ameren Illinois and Duke Energy Indiana AMI projects involved a transition from manual to automated options and these proceedings were not general rate cases. *Id.*, 15-18. Mr. Thomas discussed the robust “societal” cost beneficial test imposed in Illinois and stated that the OUCC has not identified a sound reason for supplanting the used and useful standard with the Illinois approach. *Id.*, 16. Mr. Thomas stated the Duke Energy Indiana analysis was limited to the “hard” operational savings benefits I&M had already achieved for the benefit of I&M’s customers. *Id.*, 17-18. He also disagreed with the implication that once I&M moved from manual to automated operations, the Company should discontinue its efforts to maintain its system consistent with ongoing development of technology and progress of the industry. *Id.*, 17. Messrs. Thomas and Isaacson explained the 2011 SMPP report was not a credible basis for rejecting I&M’s AMI project now because circumstances have changed since the 2011 SMPP Report discussed by Mr. Alvarez, including the maturation of AMI technology to a point where this more advanced technology has supplanted AMR. Thomas Rebuttal, 18-19; Isaacson Rebuttal, 22-23. Mr. Lucas explained I&M has incorporated lessons learned from the SMPP report, while also taking into consideration more recent advances in technology and customer expectations in designing the programs proposed in this case. Lucas Rebuttal, 3-7.

Mr. Lucas also responded to the criticism of I&M's customer engagement strategy and customer experience benefit. Lucas Rebuttal, 3-5. He showed that a 2018 J.D. Power Survey found that utility customers that are aware they have a smart meter have a higher level of satisfaction and also stated that in March 2019, the U.S. Department of Energy Office of Electricity recognized key benefits of AMI. *Id.*, 5.

Mr. Thomas explained the generic draft analysis identified by the OUCC and CAC-INCAA did not consider a systematic transition from AMR to AMI deployment (the infrastructure investment issue here) and was not completed, vetted or used by I&M. Thomas Rebuttal, 19. He added this draft analysis shows what he already knew and had taken into consideration – the readily quantifiable “hard” benefits such as labor savings are relatively small given the existing AMR technology – and the qualitative benefits are substantial. *Id.*, 19-20. Finally, Mr. Thomas explained why he disagreed the AMI proposal in this general rate case should be addressed under the standards applicable to TDSIC plans and explained why he disagreed with the OUCC's characterization of the TDSIC standard and decisions. *Id.*, 20-21.

Mr. Isaacson explained why it would be unreasonable and impractical to replace I&M's existing AMR meters with something other than AMI meters. Isaacson Rebuttal, 18-19. He said with the emergence of AMI, AMR is a declining technology and is being phased-out industry wide. He noted nearly all vendors have stopped manufacturing and supporting AMR meters; currently there remains only one vendor that supplies I&M's type of AMR meters, and the vast majority of this vendor's business is AMI. He stated it is not reasonable to rely on a single vendor to provide AMR replacements for all of I&M's AMR meters reaching the end of their service life, especially when it is not known how much longer this vendor will continue to manufacture and support this equipment. He clarified that during I&M's proposed AMI deployment, approximately 35% of the existing AMR meters will reach the end design life of 15 years. Isaacson Rebuttal, 18. He said replacing AMR meters with AMR meters would put an outdated technology in service for possibly another 15 years and would deny any realized customer benefits that he discussed in his direct testimony. He concluded that as I&M's existing AMR meters begin to reach the end of their service lives, replacing them with AMI meters is the most reasonable action. Isaacson Rebuttal, 18.

Mr. Isaacson stated that the only question is whether I&M should replace AMR meters with AMI meters in a random, reactive way, which would be much more costly and inefficient and explained why the Company's proposed systematic, proactive deployment will minimize costs and maximize benefits for customers. Isaacson Rebuttal, 18-21. Mr. Isaacson explained why waiting to deploy AMI technology while another pilot program is conducted would only serve to delay the numerous operational and customer benefits associated with AMI technology. *Id.*, 19-20. Mr. Lucas also disagreed that a collaborative pilot is necessary but offered to engage with the OUCC on the design of programs such as time of use rates, peak load management, and pre-pay, prior to I&M's next base rate case. Lucas Rebuttal, 6-7. Mr. Isaacson disagreed with Mr. Alvarez' contention regarding the AMI Michigan project and Mr. Alvarez' assertion that I&M had not considered Indiana specific issues, explaining that in identifying the Michigan template, I&M was pointing out what was being done in Michigan because I&M will be able to leverage this experience to generate efficiencies, such as taking advantage of trained, contracted work force. Isaacson Rebuttal, 21-22. Mr. Isaacson also explained why simply replacing these AMR meters upon failure with AMI technology would not be efficient and would not allow



either customers or the Company to fully realize the benefits of this new technology. Isaacson Rebuttal, 23.

5. Discussion and Finding. The record shows AMI technology has now matured and AMR technology is no longer advancing. Thomas Rebuttal, 18; Thomas Direct, 22-23; Isaacson Rebuttal, 18. The dispute among the parties centers primarily around I&M's plans to deploy the AMI technology over the three-year period from 2020 to 2022, as well as the proposal to automatically recover the expenditures through an AMI Rider. So the question is not "whether" to deploy AMI technology but rather "when" to do so, and how best to recover reasonably incurred costs. Should it be over a three-year time period or should it be organically as existing meters are naturally replaced? The magnitude of the timing question is then properly framed by considering the age of the existing meters. As of December 31, 2018, the existing meters had an average age of 10.18 years with an average remaining life of 4.82 years. Cash Direct, 3 (depreciation study evaluates utility plant as of December 31, 2018) and Cash Rebuttal, 21. Accordingly, if the existing meters were replaced organically, based on the average remaining life, they would be replaced on average by October, 2023. I&M is proposing to complete those replacements by December, 2022, or approximately 10 months sooner. This proactive replacement is efficient and lays the foundation for operational and other benefits.

Indiana applies a used and useful test to a utility's property including requests for approval of additions or improvements to its plant and equipment. Ind. Code §§ 8-1-2-6; 8-1-2-23. "The Commission's 'used and useful' standard requires: (1) that the utility plant be actually devoted to providing utility service, and (2) that the plant's utilization be reasonably necessary to the provision of utility service." *City of Evansville v. Southern Indiana Gas & Elec. Co.*, 339 N.E.2d 562, 589 (Ind. Ct. App. 1975) (citations omitted).

In this case, there is no question the Company's proposed ratemaking treatment would recognize the AMI investment through rates only once the assets are actually devoted to providing electric utility service. ~~No party has contended that the Company's estimated cost is unreasonable for AMI technology. While there is also was~~ no dispute that AMI provides substantial benefits to both the Company and its customers. ~~Rather, the OUCC and certain intervenors correctly point out that the Company did not present any evidence attempting to quantify any of those benefits in order to conduct a challenge the sufficiency of the Company's evidence regarding AMI because the Company has not provided a robust and~~ quantified cost-benefit analysis. The consumer parties did not specifically challenge the estimated cost as unreasonable. Rather, they argued that without a cost-benefit analysis, only the costs, and none of the associated savings would flow through to benefit customers. Thus, they argued that the Company should not automatically recover the costs as they are incurred.

~~Notably, the statutes and regulations that govern this proceeding do not require a quantified cost-benefit analysis. While the Commission has some discretion to weigh the evidence regarding the used and useful nature of facilities, it must also apply its decision-making in an even manner treating similarly situated utilities the same. Indiana American Water Co., Cause No. 39150, 1991 Ind. PUC LEXIS 230 at \*13-14 (IURC 6/19/1991). The Commission has not imposed a quantified cost-benefit test requirement to assess used and useful investments in other general rate cases. We are not persuaded that it is reasonable to do so here.~~

~~The Company is not proposing to deploy a new or developing technology. Rather, as shown by Mr. Thomas, AMI technology has now matured, utilities across the country, including Indiana, have or are transitioning to it, and customers have become accustomed to digital technology and real time access to data. Thomas Direct, 22-23, 25-29. Furthermore, as Mr. Isaacson explained, AMR technology has reached its maturity level and is gradually being phased out with the emergence of AMI. Isaacson Rebuttal, 18. In other words, the existing AMR technology has reached an age where it is reasonable and necessary for the Company to transition to the next generation of technology, which is AMI.~~

Ind. Code § 8-1-2-19 directs that the rates tolls and charges shall be such as will provide the amounts required over and above the reasonable and necessary operating expenses to maintain such [public utility] property in an operating state of efficiency corresponding to the progress of the industry.<sup>6</sup> Furthermore, the Commission has previously encouraged electric utilities to examine smart technologies. Thomas Direct, 23. I&M has already conducted a pilot and can leverage experience with AMI in Michigan and sister states in its Indiana deployment and use of this advanced technology. However, the Company is requesting that the Commission approve a capital investment that has an unlimited price tag. Therefore, we find that it would not be prudent at this time to approve the estimated cost related to the AMI, but rather allow the Company to establish a deferred accounting of such costs through the deployment period. Therefore, we find it would not be prudent for I&M to replace failing AMR meters with new AMR meters. Doing so would not allow I&M to maintain its utility property in an operating state of efficiency corresponding to the progress of the industry and would deprive I&M's customers of the operational and other benefits of advanced infrastructure. Accordingly, we find the proposed AMI infrastructure investment is reasonably necessary to address technological change, will improve service reliability and the customer experience, and will provide other operational benefits.

Consequently, the only~~Another~~ matter for debate is whether I&M should replace AMR meters with AMI meters in a random, reactive way, which would be much more costly and inefficient, or whether I&M should install AMI meters through the systematic, proactive deployment proposed in this proceeding, which would minimize costs and maximize benefits for customers. We find I&M should take the proactive, less costly approach. Indiana Code § 8-1-2-23 allows a utility to obtain Commission approval of expenditures for proposed additions or improvement to the utility's utility plant and equipment. Accordingly, we find I&M's proposed AMI project should be approved as to the deployment, but the costs should not be included in the rates resulting from this proceeding. The Company should be allowed to establish a deferred accounting of the AMI project costs and present such costs at its next base rate case, along with quantified benefits, where those costs and any associated savings can be reviewed and balanced. We discuss the opt-out tariff and AMI Rider below.

## **B. Distribution System Asset Renewal, Reliability Improvements and Major Projects.**

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<sup>6</sup> Ind. Code § 8-1-2-6(a) also provides for recognition of the reasonable cost of bringing utility property to its then state of efficiency.

1. I&M. Company witness Isaacson presented an overview of the Company's distribution system, its condition, and the metrics the Company uses to measure the reliability of its facilities. Mr. Isaacson discussed the Company's distribution planning and presented the Company's Distribution Management Plan, which is a comprehensive, forward-looking capital and operations plan under which the Company is making significant investments to maintain and improve the reliability of its distribution system, to enhance public safety, and to leverage technology to benefit the grid. Isaacson Direct, 2, 3-27, 34-37. Mr. Isaacson explained that much of I&M's system was built in the 1960s and 1970s, when I&M's territory experienced growth. He said an increasing portion of assets are now reaching the end of their expected design lives. Mr. Isaacson testified although age alone does not determine when assets fail, assets are more likely to fail when they reach the end of their design life, and older assets can be harder to replace when they fail because it is often difficult to obtain available parts for aging equipment. He said older assets also pose safety risks from failures during operation. *Id.*, 4. Mr. Lucas also supported the distribution components of the Company's capital investment. Lucas Direct, 17.

2. OUCC. Mr. Alvarez recommended the Commission reject over \$75.12 million in 2019 and 2020 distribution system asset renewal and reliability capital projects from rate base (and exclude associated O&M) until I&M provides project status and work order details enumerated in OUCC testimony and the other parties have time to conduct independent review and evaluation. Alvarez, 3, 20-30, 38. He also recommended the Commission reject \$32.57 million in 2019 and 2020 distribution system major projects (and associated O&M) and require I&M to provide detailed project cost estimates with the corresponding approved Capital Improvement Requisition for each Major Project prior to approval. *Id.*

3. Rebuttal. Messrs. Thomas and Williamson explained the Company's case-in-chief and workpapers included the information required by the governing statute and MSFRs. Thomas Rebuttal, 3-4; Williamson Rebuttal, 40-51. Mr. Isaacson detailed the considerable support and documentation provided in the Company's case-in-chief and workpapers showing the reasonableness of I&M's Distribution Management Plan. Isaacson Rebuttal, 3-4, 8. Mr. Williamson and Mr. Isaacson also discussed the Company's meeting with the OUCC and other information provided to the OUCC through the discovery process. Williamson Rebuttal, 49-50; Isaacson Rebuttal, 4-8. Mr. Isaacson explained it is appropriate to use parametric estimates for the projects in the Asset Renewal and Reliability program (*e.g.*, poles, cross-arms, porcelain cutouts, cable) because the work has been performed repeatedly over many years. Isaacson Rebuttal, 7. He added that providing Class 2 cost estimates for projects two years out is unnecessary and would add costs needlessly. *Id.* Mr. Isaacson explained Mr. Alvarez' criticism of the distribution "indirect costs" appear to reflect a misunderstanding of the Company's definition of "indirect costs" and also fails to recognize the difference in how indirect costs are treated in contract labor costs compared to Company labor costs. *Id.*, 10. Mr. Isaacson clarified the major projects are more complex projects that I&M has identified as necessary to improve the reliability of the system, to improve the ability to serve increased load, and to promote safety and enhance the technological capabilities of I&M's system. *Id.*, 10-11. He referred to the definition, documentation and other details provided in his direct testimony and in the Company's discovery responses. *Id.*, 10-11. He said the details included project justification, benefits, project start and end dates, total cost, material cost, internal and contractor labor cost, and total indirect cost and were consistent with the information provided in the Company's direct testimony in Cause No. 44967. *Id.*, 11. He explained while a Major Project can have a



transmission component, all projects and costs in the Distribution Management Plan are distribution projects and do not include any transmission investment. *Id.*, 12.

4. Discussion and Finding. The OUCC proposes the Commission disallow tens of millions of dollars of capital investment in 2019 and 2020 on the grounds that the Company's case-in-chief was inadequate. We note at the outset that neither Section 42.7 nor the MSFRs require the level of detail sought by Mr. Alvarez to be provided as part of the Company's case-in-chief and workpapers. The MSFRs are intended "to assist the commission in thoroughly and expeditiously reviewing a petition for a general rate change . . . ; . . . provide support for the electing utility's rate petition; and . . . reduce or avoid disputes." 170 IAC 1-5-2(a); Williamson Rebuttal, 42. In particular, the information related to utility plant and capital projects that a utility must submit is enumerated in 170 IAC 1-5-9 and 170 IAC 1-5-10. These requirements capture the information sufficient to allow the OUCC or any other party to review the reasonableness of a utility's capital projects and rate base additions. Here I&M submitted the information required under 170 IAC 1-5-9 and -10, and therefore, with respect to capital projects and rate base additions and reasonably expected that it had submitted a complete case-in-chief. We also note that the MSFRs direct concerns regarding the sufficiency of a petitioner's case-in-chief to be raised and addressed up front at the time the procedural schedule for the rate case is established. 170 IAC 1-5-4(a); 170 IAC 1-5-2.1(c); Williamson Rebuttal, 43. The Commission also has a procedure that allows concerns about the discovery process to be raised and resolved by the Commission. 170 IAC 1-1.1-16(d). No party utilized either of these procedures.

Instead, Mr. Alvarez presented a list of 19 additional informational requirements that should be required "at a minimum" to support the Company's distribution system investment (and associated O&M). Alvarez, 28-29. We disagree that project reference numbers, identifiers, work request numbers, project stop and start dates and the additional details included on Mr. Alvarez' list are necessary for the Commission to assess the used and useful nature and associated cost of the Company's ongoing investment. Furthermore, a utility can best manage its business in the public interest when the regulatory framework is stable. Imposing the new requirements urged by Mr. Alvarez in the middle of a general rate case is unfair and if adopted could result in the unintended adverse consequence of indicating to capital markets that the standard applied to utility investment is ever changing. For us to announce a list of 19 "minimum" requirements that must be included in a petitioner's case-in-chief that would govern how we review a rate base forecast in this and other cases would require rulemaking. Accordingly, we decline to adopt Mr. Alvarez' recommendation.

This is a forward-looking test year case under Ind. Code § 8-1-2-42.7(d)(1). This statute requires our determination to be made "on the basis of projected data." *Id.* For purposes of rate base projections, we are guided by our standard for preapproval of expenditures pursuant to Ind. Code §8-1-2-23. Our established standard for preapproval under that section confirms that we are not approving specific items of utility property or projects, but rather we are approving "expenditures" for improvements. As we announced in *American Suburban Utils*:

Petitioner has requested relief pursuant to Section 23 in this proceeding. When faced with such a request, the first question we must ask is whether an expenditure of any amount is reasonably necessary to assure reasonable and adequate service. If so, we must proceed to the second question: what amount

reasonably needs to be invested? Once we answer the first question affirmatively, we cannot simply deny in its entirety a request for approval of expenditures. If we did, it would mean that we would deny approval for any amount of expenditures even though we have already found that some level of expenditures is necessary for the provision of reasonable and adequate service. Such a result would be counter to our very purpose. *See Indiana-American*, p. 18 (“We simply cannot condone the OUCC’s approach, which we find would lead to inferior water quality and customer complaints.”)

Cause No. 41254, p. 14 (IURC 4/14/1999), 1999 WL 397655 at 10. For purposes of projecting rate base in a forward-looking test year, this is the appropriate lens through which we should review the forecast. We know for a utility such as I&M that it must continually make expenditures for improvements to its system in order to continue providing reasonably adequate service and facilities. A petitioning utility should describe how it arrived at its projection and why improvements of the types that are forecasted are reasonably needed. The particular need for more significant projects should be provided. For mass property accounts that tend to be more reactionary, such as pole replacements as a result of inspections or accidents, we would expect the projection to be based upon historical experience. If the overall projected additions are going to differ significantly from historical expenditure levels, the petitioner should explain why.

Here, for the more routine distribution improvements, Petitioner identified approximately 670 projects in Attachment DSI-1, complete with total cost and number of units. For each major distribution project, Petitioner included in Attachment DSI-2 a project description, an explanation of the need for the project, and identified the benefits of the project. Mr. Isaacson described how the projections were prepared and how the various projects were identified. Isaacson Direct, 7-27. No one disputed that there is a need for expenditures for any of the improvements discussed and identified by Mr. Isaacson. Instead, the OUCC’s objection is that the cost estimates are not sufficiently refined – the OUCC does not contend that the projections are excessive. Under the *American Suburban* standard, the OUCC’s objections are not a sufficient reason to reject *in toto* Petitioner’s projected expenditures. Given that there is no dispute that some level of expenditure is needed, “we cannot simply deny in its entirety a request for approval of expenditures.” *American Suburban*, p. 14. The best evidence that we have of the amount that is reasonably needed is the projection provided by Mr. Isaacson.

The record shows, and we find, the Company has complied with the governing statute and MSFRs and has cooperated throughout the discovery process. In doing so, the Company provided the information necessary for its investments to be reviewed. We also reject the premise that the Company’s data and sworn testimony must be independently verified. “[T]he law has long recognized that good faith is to be presumed on the part of the managers of a public utility like I&M.” *Re Indiana Michigan Power Co.*, Cause No. 39314 at 5, 1993 WL 602559 (IURC 11/12/1993). This presumption is reinforced by the law’s recognition of a presumption of correctness of the utility’s books and records. *Id.* “Particularly when a given level of revenue, expense or rate base is supported by the testimony of knowledgeable Company officials or duly qualified expert witnesses, this Commission cannot disregard the sworn testimony of such witnesses.” *Id.* at 5. Substantial record evidence demonstrates that the Company has exercised a proper discretion with respect to its business judgment that the infrastructure investment is necessary. “The Commission is not the financial manager of the corporation, and it is not

empowered to substitute its judgment for that of the directors of the corporation”. *Southwestern Bell Tele. Co v. Pub. Serv. Comm’n of Missouri*, 262 U.S. 276, 289 (1923).

Accordingly, we reject the OUCC proposal to disallow the Company’s 2019-2020 distribution capital investment on the grounds that the Company failed to provide adequate information in its case-in-chief. The Company provided all the information required by the governing statute and the MSFRs, if not more, and its presentation in this case is consistent with that in prior cases where the level of detail was not viewed as inadequate.

The issue of whether additional evidence is required in a TDSIC filing is a separate matter and does not change the rules applicable to a general rate case, where the selected forward looking test period is allowed by statute to be “determined on the basis of projected data.” Section 42.7(d)(1). See Williamson Rebuttal, 41-42.

**C. Rockport Enhanced Dry Sorbent Injection (“DSI”) System.**

1. I&M. Mr. Thomas explained both units of the Rockport Plant are equipped with flue gas scrubbing technology that uses DSI equipment to inject dry sorbent (sodium bicarbonate) into the flue stream to reduce hydrochloric acid (“HCl”) and sulfur dioxide (“SO<sub>2</sub>”) emissions. Thomas Direct, 15. The Commission authorized the use of the DSI system at Rockport in Cause No. 44331. As stated by Mr. Kerns, the Rockport Plant utilizes the DSI system to meet reduced SO<sub>2</sub> emission limits required under the Plant’s air permit. Kerns Direct, 24. He said this SO<sub>2</sub> limit becomes more stringent over multiple years, with lower SO<sub>2</sub> emission limit taking effect on January 1, 2018, and January 1, 2020. *Id.* He added that in response to the stepped reduction SO<sub>2</sub> limit, I&M will increase the injection rate of sodium bicarbonate. *Id.*

As discussed by Mr. Kerns, during the Test Year, the Company plans to place certain enhancements to the DSI system into service at an estimated capital cost of approximately \$13.3 million, which is significantly less than the cost of the alternative control – a dry scrubber. Kerns Direct, 30; Thomas Direct, 17-18. Mr. Thomas testified this capital investment will enhance the performance of the DSI equipment by moving the injection point of the sodium bicarbonate into the flue gas stream upstream of its current location. Thomas Direct, 15. Mr. Kerns said the DSI enhancements will result in approximately an \$8 million incremental increase in O&M expenses that is mostly consumables expense. Kerns Direct, 30-31. Mr. Thomas explained the enhanced DSI is required to comply with the Fifth Modification of the Consent Decree and stated that the project is a reasonable means of maintaining the availability of low cost, coal-fired generation that complies with environmental regulations, allows the plant to continue to serve customer needs provide jobs and taxes to the community, and does so in a manner that mitigates the rate impact on customers. Thomas Direct, 18-19.

2. OUCC. The OUCC recommended the Commission deny recovery of the DSI investments for both Rockport units and exclude the associated O&M from the revenue requirement because the project stems from the Fifth Modification of the Consent Decree and the OUCC opposes burdening ratepayers with the Consent Decree’s costs. Armstrong, 9, 7-8, 11. Ms. Armstrong added that the DSI enhancements should also be rejected

because the Rockport Unit 2 lease expires in December 2022 and I&M failed to include the enhanced DSI project costs in its 2019 Integrated Resource Plan (“IRP”). *Id.*, 9-10. In the alternative, the OUCC recommended the Commission disallow the cost recovery related to the Rockport Unit 2 DSI enhancements. *Id.*, 10-12. Ms. Armstrong added I&M should still take action to keep Rockport operational, and the OUCC is not recommending I&M terminate the Unit 2 lease early. *Id.*, 11.

3. Intervenors. While the Industrial Group took no position as to the prudence or reasonableness of I&M’s proposed installation of the enhancements to the DSI system at Rockport, Mr. Gorman noted a possibility that some portion of the Rockport Unit 1 costs can be recovered from the lessors. Gorman, 40-41. He recommended that if the Commission approves cost recovery for this investment it should require I&M to reimburse customers for any costs recovered pursuant to the terms of the lease. *Id.*

Alliance witness Norfleet argued Ms. Armstrong’s analysis does not look at the fuller picture of how AEP’s choices may impact the dispatch and retirement of plants ratepayers have funded and does not consider additional ways to mitigate the harm to ratepayers by requiring I&M to look for ways to keep Rockport Unit 2 in operation past the planned retirement date. Norfleet, 3.

4. Rebuttal. Mr. Thomas explained the OUCC recommendations are based on a flawed understanding of the Consent Decree and the manner in which it came about. Thomas Rebuttal, 21-22. He testified the execution of and modifications to the Consent Decree are not the result of “questionable management decisions,” as alleged by Ms. Armstrong, but have been a series of actions taken by AEP to comply with evolving environmental requirements in a cost effective manner that have avoided the expenditure of billions of dollars. Mr. Thomas explained that the Rockport Units have gained a significant advantage by participating in the Consent Decree as the Rockport Units have the latest compliance dates of any units in the AEP system for installing post-combustion SO<sub>2</sub> and NO<sub>x</sub> controls and this means I&M customers will benefit from the proven performance of lower-cost DSI technologies that have only recently become available. Thomas Rebuttal, 22. Mr. Thomas testified regardless of whether the lease is renewed or not, the modest adjustment to the DSI system is reasonable because it optimizes the use of the existing equipment, relocates the injection point for the dry sorbent, takes advantage of mixing plates that are included in the SCR design for both units, and thereby significantly increases the achievable SO<sub>2</sub> removal efficiency. Mr. Thomas noted the continued uncertainty about future environmental requirements and said the DSI enhancements provide additional compliance margin for a new standard currently under review by the U.S. EPA. Thomas Rebuttal, 23-24.

Mr. Thomas stated the consequences of non-compliance with the terms of the Consent Decree would be severe because the units cannot comply with the thirty-day average emission rates if the DSI Enhancement Project is not in operation by the end of 2020. Thomas Rebuttal, 24. He said the lease requires I&M to return Rockport Unit 2 to the lessors at the end of the lease term in a condition to comply with all of the applicable environmental requirements. Thomas Rebuttal, 24. He added the lease was approved by the Commission and I&M must continue to comply with the lease through its full term. Thomas Rebuttal, 24. Mr. Thomas stated I&M’s

customers benefit more from the enhanced DSI system than they would from any alternative means of complying with the terms of the lease. Thomas Rebuttal, 24.

Mr. Thomas stated Ms. Armstrong confused two different versions of the Fifth Modification of the Consent Decree, explaining that Ms. Armstrong discussed a contested motion filed by AEP, not the settlement agreement among all parties that became the Fifth Joint Modification. *Id.*, 24-25.

With respect to the IG recommendation, Mr. Thomas stated that while it may be appropriate to credit I&M's depreciation accounts with amounts receive from the transfer of assets to the Lessors upon the expiration of the Rockport Unit 2 lease, it would be inappropriate to create a refund obligation to customers. Thomas Rebuttal, 25-26. He added that I&M will act in accordance with the requirements of the Lease and good accounting practice to reflect the appropriate amounts in the appropriate accounts.

5. Discussion and Finding. We now turn to the OUCC proposed disallowance of the cost of the enhancements to the DSI system. At bottom, Ms. Armstrong's contention rests on the false premise that this cost is unreasonable and excessive. Her recommendation fails to recognize that the Commission authorized the use of the DSI systems at both Rockport Units in its Order dated November 13, 2013, approving the settlement agreement in Cause No. 44331. In that proceeding, Armstrong testified that "[t]he DSI systems are necessary for I&M to comply with, MATS, CAIR, CSAPR, and the NSR Consent Decree." Thomas Rebuttal, 23, fn. 8 (citing Cause No. 44331, Public's Exhibit No. 2, 16). The Order in Cause No. 44331 found that I&M considered several alternative plans for compliance with the federally mandated requirements, in addition to the SCR and FGD projects originally required by the Consent Decree and that the evidence demonstrated that the Rockport CCT Project is a cost-effective method to achieve compliance with the MATS Rule. *Re Indiana Michigan Power Co.*, Cause No. 44331 at 25 (IURC 11/13/2013). The Commission also found that the installation of the Rockport CCT Project will preserve, if not extend, the remaining lives of the Rockport Units and the "Rockport CCT Project is the best option to permit Rockport to continue to provide generation needed to serve I&M's customers' needs." *Id.*, 26. We decline to revisit matters resolved in Cause No. 44331.

Ms. Armstrong agrees that I&M should take action to keep Rockport operational, and should not terminate the Unit 2 lease early, but she recommends the Commission disallow the cost of the DSI enhancements. Armstrong, 11. This position is illogical because the cost of the DSI enhancement is necessarily incurred to keep Rockport in service and avoid more costly lease compliance requirements, including early termination of the lease. The OUCC position reflects a fundamental misapplication of the basic tenets of utility regulation and would essentially take the capital contributed by shareholders and not allow I&M to earn a return on or of that capital when setting rates.

As shown by OUCC Attachment CMA-3, the Company's IRP does contain the DSI Project approved in Cause No. 44331. While the modeling for the IRP submitted on July 1, 2019 was completed prior to the release of the revised consent decree language that requires enhancements to the DSI equipment, I&M conducted an analysis of plant investments on Rockport Unit 2 that demonstrates these investments, including the enhanced DSI project,

continue to be more economic than terminating the lease early. *Id.* Furthermore, the IRP submitted on July 1, 2019 includes a scenario where an FGD system is installed on Rockport Unit 1 by December 2028 for approximately \$1.4 billion. *Id.*

The record shows that the enhancements to the DSI system are forecasted to be in service during the Test Year. Kerns Direct, 15. The record further shows that completing this project substantially lowers the cost of environmental compliance at Rockport and may also support compliance with new regulations under consideration by the U.S. EPA. Thomas Direct, 18; Thomas Rebuttal, 24.

Accordingly, we find substantial evidence demonstrates that the enhancements are used and useful in the provision of retail electric service and the cost is not excessive. Therefore, we reject the OUCC proposal to disallow the cost of the enhancements to the DSI system.

**D. Rockport Coal Combustion Residuals (“CCR”) Compliance Project.**

1. I&M. Mr. Kerns testified the CCR rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximately four-year implementation period. He said Rockport’s compliance with the CCR rule – which primarily consists of the discontinued use of the east bottom ash pond and inciting closure – is currently projected to be completed by May 31, 2020 at a total cost of \$4.069 million (including AFUDC). Kerns Direct, 14.

2. OUCC. Ms. Aguilar testified closure of an ash pond results in that asset no longer being used and useful and does not extend the generating capabilities of the Rockport Plant. Aguilar, 23. She stated closure costs are not appropriately collected as a capital expenditure and said I&M did not provide sufficient information to establish the cost will be incurred within the test year. Aguilar, 27.

3. Rebuttal. Mr. Kerns testified I&M continues to refine the details of the forecasted CCR project, and said it is possible that some of the forecasted capital costs will be reclassified as fuel or closure costs. Kerns Rebuttal, 8. He said I&M can confirm that at least \$798,000 (including AFUDC) of the forecasted \$4,069,000 (including AFUDC) are properly classified as capital costs and will not be reclassified. As for the remaining \$3,271,000, he said I&M is amenable to removing this amount from I&M’s forecasted rate base in this proceeding and addressing these costs in future I&M regulatory proceedings. Kerns Rebuttal, 8-9.

4. Discussion and Finding. We find I&M’s rebuttal position reasonably addresses the OUCC’s concerns. Accordingly, we find I&M’s rate base should include \$798,000 (including AFUDC) associated with the CCR project. I&M may address the remaining CCR project costs in future regulatory proceedings.

**E. Rockport Unit 2 High Pressure (“HP”) Turbine Replacement Project.**

1. I&M. Mr. Kerns explained this project involves rebuilding the Unit 2 HP turbine, including the installation of the system spare turbine rotor and inner shell (inner



block) and blade carriers during a scheduled Unit 2 outage in 2020. He said the 1300 Series turbines have a service life of eight to ten years based on good engineering practices. He stated this project is forecasted to be placed in service by June 1, 2020 at a total cost of \$1.323 million (including AFUDC). Kerns Direct, 15.

2. OUCC. Mr. Alvarez stated it is unreasonable to ask ratepayers to fund the replacement and/or rebuild of the turbine that will provide I&M's customers with electricity only through 2022. He recommended removal of \$1.323 million (including AFUDC) in capital expenditures and all O&M expenditures associated with the HP turbine replacement project. Alvarez, 4, 36-37.

3. Rebuttal. Mr. Kerns stated not rebuilding the Unit 2 HP Turbine exposes I&M and its customers to more risk. Kerns Rebuttal, 5. He explained with a turbine rebuild in 2020, the HP turbine will remain below the 80,000 service hour threshold and retain the risk assessment ranking of "Notice" (<10% probability of failure). He said it is prudent utility practice to avoid a turbine failure (which would cause extensive damage and result in a lengthy forced outage) and that the HP turbine rebuild project is the reasonable course of action regardless of whether the Unit 2 lease will expire at the end of 2022. Kerns Rebuttal, 6-7. He added that failure to rebuild or replace the HP turbine subjects I&M to the risk of future litigation should the work not be performed. *Id.* at 8.

4. Discussion and Finding. The record shows the Unit 2 HP Turbine Replacement Project is consistent with prudent utility practice and avoids increasing the risk assessment ranking for the turbine. The failure of a rotating or stationary blade will cause extensive damage and result in a forced outage of, at minimum, eight weeks. Kerns Rebuttal at 6. In addition to increased capital and O&M costs, Unit 2 would be unavailable during this repair timeframe. As Mr. Kerns noted, collateral damage due to a turbine failure cannot be accurately predicted and could be greater. Kerns Rebuttal, 7. While the OUCC objected to the project based on the current expiration date of the Unit 2 lease, the record shows the HP turbine rebuild is the reasonable course of action regardless of whether the Unit 2 lease will expire at the end of 2022. Accordingly, we reject the OUCC's proposed disallowance associated with this project.

#### **F. South Bend Solar Project ("SBSP").**

1. I&M. Mr. Kerns testified that if the SBSP is approved by the Commission in Cause No. 45245, it is forecasted to be placed in service by December 31, 2020 at a total cost of \$29.303 million (including AFUDC). Kerns Direct, 13.

2. OUCC. Mr. Blakley recommended that the cost of I&M's SBSP be removed from rate base in this proceeding based on the OUCC's recommendation in Cause No. 45245 that such costs be recovered through a tracking mechanism if the project is approved. Blakley, 11-14, 15.

3. Rebuttal. Mr. Williamson explained that I&M disagrees with the OUCC's proposal to track the SBSP and said he expects the Commission to decide this issue in the separate pending case. He recommended for purposes of this rate case that the SBSP project

costs be included in rate base, as proposed by I&M, if the project is approved. Williamson Rebuttal, 68.

4. Discussion and Finding. The record shows that if the SBSP is approved by the Commission in Cause No. 45245, it is forecasted to be placed in service during the Test Year. The issue before us is whether the Commission should decide the accounting and ratemaking for the SBSP in the instant case or in Cause No. 45245. Developments in Cause No. 45245 aid this determination. The Commission takes administrative notice that on October 31, 2019, a docket entry was entered in Cause No 45245 which granted the unopposed joint petition to re-open the record in that proceeding to receive a settlement agreement of all issues among all the parties. Accordingly, we find it reasonable for purposes of this rate case that the accounting and ratemaking for the SBSP project be based on the outcome of Cause No. 45245.

**G. Prepaid Pension Asset.**

1. I&M. Aaron L. Hill, Director of Trust for AEPSC, testified in support of the continued inclusion in rate base of Petitioner's prepaid pension asset. He noted this treatment is consistent with the Commission's Orders in Cause Nos. 44967 and 44705. He said the prepaid pension asset is defined as the cumulative cash contributions to the pension fund in excess of the cumulative pension cost. Hill Direct, 37. He explained the process for forecasting the prepaid pension asset, including forecasted contributions and costs.

2. OUC. Margaret A. Stull testified in opposition to the continued inclusion in rate base of the prepaid pension asset. She testified the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") does not define the term "prepaid pension asset". Stull at 3. For ease of understanding, Ms. Stull used the term "prepaid pension asset" to refer to the difference between cumulative pension contributions and cumulative pension cost. She also used the term "excess pension contributions" to have the same meaning as "prepaid pension asset." *Id.* at 4. She claimed I&M provided no support that the asset was funded by investor-supplied capital. *Id.*, 12. She set forth the OUC's position on prepaid pension assets, to wit that a prepaid pension asset is not used and useful plant under Ind. Code § 8-1-2-6. She contended that it cannot be considered inventory or a prepaid asset, nor is it working capital. *Id.* at 14. Neither should the prepaid pension asset be included in the capital structure at zero cost under the OUC's view. *Id.*, 16. To recognize that the prepaid pension asset lowers pension cost, she proposed an alternative calculation for pension expense for ratemaking. She determined the cumulative amount of Employee Retirement Income Security Act ("ERISA") minimum contributions in excess of cumulative pension costs, which excluded any "discretionary contributions" to the fund. She then multiplied the excess of the ERISA-required contributions by the 6.25% return on plan assets from the actuarial report and added this amount to pro forma pension expense. *Id.*, 18. She said her proposal would result in further adjustments being necessary in I&M's next base rate case and thereafter. *Id.*, 20.

3. Intervenors. IG witness Michael Gorman objected to the continued inclusion of the prepaid pension asset in rate base on the basis that Petitioner had not included in its evidence that the asset was funded by investor capital, nor justification of why Petitioner should be allowed to earn a return on the asset. Gorman, 12. He argued to the extent the contributions are funded by ERISA minimum funding requirements, the costs had already been



recovered through rates and not supplied by investor contributions. He also argued to the extent the return on pension trust assets was large enough to offset the pension service costs and interest costs, that this also was not funded by investors. *Id.*, 13. In his view, evidence would need to be supplied that the prepaid pension asset was directly the result of capital provided by investors.

4. Rebuttal. Petitioner's witness Hill noted that I&M's cumulative pension cost is greater than the cumulative minimum ERISA contributions, and so the minimum required contributions are not included in the prepaid pension asset. Furthermore, he noted that minimum required contributions are a legal obligation and would still need to be included even if they did make up a part of the prepaid pension asset. Hill Rebuttal, 16-17. He further objected to Ms. Stull's alternative calculation of pension expense, which he called a fictitious and hypothetical cost calculation. *Id.*, 19. He described the prepaid pension asset as prepayment of an allowable cost which directly reduces annual pension costs. He said the reduction for 2018 was approximately \$5.1 million, and for 2020 was forecasted to be approximately \$7.7 million. *Id.*, 22. He explained without the prepaid pension asset, 2020 pension costs would instead be projected to total nearly \$13 million. He said if the Commission were to exclude from rate base the prepaid pension asset, these savings should be removed from the cost of service as well as the benefits from their compounding effects. *Id.*, 23. He also stated the contributions and return result in the avoidance of the variable Pension Benefit Guaranty Corporation premiums. *Id.*, 23.

Tyler H. Ross, Director of Accounting and Regulatory Services for AEPSC, testified the prepaid pension asset does exist on Petitioner's books and records and is consistent with GAAP. Ross Rebuttal, 2. He disagreed that the prepaid pension asset was funded by any source other than investor capital. He said I&M's customers pay rates that reflect the level of GAAP-determined pension costs. He explained I&M does not recover through rates any pension amount above and beyond that level since the prepaid pension asset consists of cumulative contributions to the pension fund less the GAAP-determined cost; it is funded solely by investors. *Id.*, 10-11. He testified these contributions earn returns that benefit customers through lower pension costs and that therefore the prepaid pension asset represents a prudent investment made to help meet utility obligations, reduces cost of service for customers, and is therefore used and useful in providing public utility service. *Id.*, 11. He described the investment as akin to working capital, fuel inventory, materials and supply, and prepayments. *Id.*, 12. He explained the prepaid pension asset has been included in rate base for many years, that it has existed on I&M's books since 2005, was expressly approved for rate base treatment in Cause No. 44075, and most recently again in Cause No. 44967. He noted the level included in I&M's forecast in this rate case is actually less than the level included in rate base in the last rate case. *Id.*, 14.

5. Discussion and Finding. We found in Cause No. 44075:

The record reflects that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards. The record also reflects that the prepaid pension asset has reduced the pension cost reflected in the revenue requirement in this case and preserves the integrity of the pension fund. Petitioner made a discretionary management decision to make use of available cash to secure its pension funds and reduce the liquidity risk of future payments. In addition, the prepayment benefits ratepayers by reducing total pension costs in

the Company's revenue requirement. Therefore, we find that the prepaid pension assets should be included in Petitioner's rate base.

*Indiana-Michigan Power Co.*, Cause No. 44075, p. 10, 2013 WL 1180842 (IURC 2/13/2013). The OUCC appealed that finding and our order was affirmed on appeal.

We find no change in circumstances that would cause us to change our view of the prepaid pension asset. Indeed, even the amount of the prepaid pension asset to be included in rate base (\$62,209,786)<sup>7</sup> is similar to the \$61,691,738 which we found should be included in rate base in that Cause. The fact that the prepaid pension asset is forecasted to be nearly the same amount that it was nine years earlier belies Ms. Stull's concerns that the prepaid pension asset will grow to be the largest asset in Petitioner's rate base. Stull, 4, 16. We are persuaded by Mr. Ross that the prepaid pension asset continues to be reflected on I&M's books pursuant to GAAP. We further find, and as will be further explained in our finding on pension expense, that the prepaid pension asset continues to reduce overall pension costs, which is reflected in the cost of service. It therefore continues to provide benefits to customers. The prepaid pension asset is akin to working capital, materials and supplies, and other prepayments and should similarly be reflected in rate base. As recognized in the Commission Order in Cause No. 44576 (p. 23), materials, supplies, and fuel inventory are typically included in utility rate base, *i.e.*, used and useful utility property, and while they may not be expressly identified as working capital, those items reasonably constitute working capital. Put another way, these items recognize capital that has been put to work for the purpose of providing utility service. While a "cash" working capital allowance is one type of "working capital", it is not the only type.<sup>8</sup> Recognizing working capital in rate base is an appropriate method of compensating investors for the cost of capital which they have advanced in the course of providing service. We reject the OUCC contentions to the contrary. Finally, we find from the very nature of the calculation of the prepaid pension asset, that the entirety of the prepaid pension asset was funded by investors. Customer rates have only reflected the level of pension expense calculated pursuant to GAAP. The prepaid pension asset is the cumulative total of cash contributions *in excess of* cumulative pension expense pursuant to GAAP. It is not, as Mr. Gorman testifies, the result of growth in the pension fund through return on pension assets; rather its calculation is directly from cash contributions. In other words, the prepaid pension asset reflects cash amounts contributed over and above the level of costs that have been recovered through rates charged to customers. All of it has necessarily been supplied by investor capital. Accordingly, we find the prepaid pension asset should continue to be reflected in rate base and that the proposals of the OUCC and Intervenors should be rejected.

**H. Unamortized Nuclear Decommissioning Study and Rate Case Expense Asset.**

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<sup>7</sup> In response to an informal discovery inquiry, I&M stated that Petitioner's original proposal incorrectly included amounts related to the unregulated River Transportation Division; therefore the amount of the prepaid pension asset on an Indiana jurisdictional basis is \$62,209,786. Stull, 9-10.

<sup>8</sup> See *Re Indianapolis Power & Light Co.*, (IURC 3/16/2016), Cause No. 44576 p. 23 n. 4, distinguishing allowance for "cash" working capital (requiring lead-lag study) from overall finding that materials, supplies, fuel inventory and prepaid pension asset are reasonably categorized as working capital.

1. Petitioner. As will be explained hereinafter, Petitioner is proposing to amortize its deferred rate case expense over a period of two years. The Company is proposing the deferred amount be included in forecasted rate base. Williamson Direct, 30.

2. OUCC. OUCC witness Eckert recommended deferred rate base expense and nuclear decommissioning study be excluded from rate base. He contended I&M's proposal goes beyond basic ratemaking principles and is unreasonable. Eckert, 17.

3. Petitioner's Rebuttal. Mr. Williamson explained the OUCC's view is too narrow and that rate case expenses are reasonable and necessary costs incurred to provide service to customers. He explained carrying costs are intended to compensate for the time value of money associated with an expenditure that is recovered over a period of time. He said deferring a recovery of these costs creates an asset, and it is reasonable to earn a return on that asset no different than other assets involved in the provision of electric service. Williamson Rebuttal, 39.

4. Commission Findings. Rate case expense is a reasonable and necessary cost of providing utility service and, when it is to be recovered over a period of time, full recovery of rate case expense would be denied if we did not authorize the inclusion of the deferred amount in rate base. In this respect, rate case expense is akin to the baffle bolt expense which is being deferred and amortized over a period of years, per our Order in Cause No. 44075. For the same reason, the unamortized portion of the expense should be included in rate base.

## **I. Conclusion on Rate Base.**

Based upon the foregoing findings, the Commission finds that the Test Year End net original cost rate base (Indiana Jurisdictional) for I&M is \$4,918,317,686 and is calculated as follows:

Net Plant in Service	\$	4,694,496,954
Fuel Stock	\$	23,146,671
Other Materials & Supplies	\$	116,811,112
Allowance Inventory	\$	17,043,356
Prepaid Pension Expense	\$	62,209,786
Regulatory Assets	\$	58,268,143
Deferred Gain Rockport 2 Sale	\$	(5,061,526)
Regulatory Liabilities	\$	(2,588,975)
Deferred Income Taxes	\$	(46,007,835)
Original Cost Rate Base	\$	<u>4,918,317,686</u>

7. Depreciation. I&M witness Cash performed a depreciation study for I&M's electric plant as of December 31, 2018. Mr. Cash discussed the methods and procedures used in preparing the depreciation study and recommended an overall increase in I&M's depreciation accrual rates. We discuss the challenges to Mr. Cash's proposed depreciation accrual rates below.

A. Accounts 354, 355, 364, 365, 366, 368, 369.

1. OUCC. OUCC Witness David Garrett used the same Simulated Plant Record (“SPR”) Method used by Mr. Cash for purposes of evaluating mass property accounts when aged data is not available for certain accounts. D. Garrett (Part 2), 28, 30. He said with aged data, the ages of assets retired is known and an actuarial analysis can be conducted to recommend service lives. But with unaged data, the ages of retired assets must be “simulated.” This is the SPR method. *Id.* He said the Conformance Index (“CI”) and the Retirement Experience Index (“REI”) are the statistics that provide the quality of the fit for the Iowa Survivor Curve. *Id.*, 30-31. He used “scales” set forth in a 1947 paper written by Alex Bauhan to assess the CI and REI. *Id.* p. 30, n.26, 31-32. Based on these scales, Mr. Garrett testified the Iowa Survivor Curves selected by Mr. Cash are not good. *Id.* at 32. Based in part on data from other utilities, he proposed adjustments to the service lives for Accounts 354, 355, 364-366, and 368-69. *Id.*, 34-35.

2. Industrial Group. IG witness Andrews opposed the proposed rate for Accounts 364, 365, and 368. He testified when sufficient data concerning the year of installation and retirement for each vintage exists, the actuarial analysis approach can be conducted. Andrews, 7. In his opinion, I&M’s SPR analysis results in service lives for these accounts that are too short based on the scale set forth in Mr. Bauhan’s 1947 paper. *Id.*, 15-18. Mr. Andrews testified the CI showed a poor fit based on the scale set forth in Mr. Bauhan’s 1947 paper. *Id.*, 16-17. Mr. Andrews instead based his recommendation on his informed judgment. He based his analysis on the average service lives from other utilities. *Id.*, 18. He recommended average service lives for Account 364 of 47 years; for Account 365 of 48 years; and for Account 368 of 40 years. *Id.*, 20.

3. Rebuttal. Mr. Cash testified he had not relied solely on the CI, and that instead he had also considered a number of other factors, including the retirement experience index as well as the survivor curves and average service lives that were approved in prior depreciation studies. Cash Rebuttal, 24. He explained the Bauhan scale is arbitrary. Cash Rebuttal, 23. Mr. Cash stated he mainly focused his comparison to the results from the last two approved depreciation studies because there was no indication that the Company’s historical data, and thus the resulting survivor curve and average service life assigned to each account, should not be used. Cash Rebuttal, 24-25. He explained the results from the Company’s analysis must be given primary weight since the factors that affect the retirement of property are typically different for every company. *Id.* Mr. Cash also compared his proposed Iowa Survivor Curves for these accounts to those proposed by Mr. Garrett and Mr. Andrews as well as to those that had been approved for comparable AEP affiliates. *Id.* at 25; Attachments JAC-R1 and JAC-R2. Mr. Cash explained the comparison to other nearby AEP affiliates validates the results of his analysis and confirming that it is reasonable. *Id.* at 25. He added his comparison also shows that the proposed services lives proposed by witnesses Garrett and Andrews are significantly outside the range of comparable AEP affiliates that have similar operating conditions to I&M. *Id.*

4. Discussion and Finding. The selection of the appropriate survivor curve involves the use of professional judgment, more so when as here the SPR Method must be used because of the lack of aged data. The OUCC and Industrial Group seek to use curves that have much longer service lives than those selected by Mr. Cash, and they do this based upon data

gathered from other utilities. We decline the OUCC and Intervenor invitation to reject the Company's analysis based on arbitrary scales from an unpublished 1947 Bauhan paper. We find the most compelling data is set forth on Page 23 of Mr. Cash's rebuttal, where he compares his proposed survivor curves to the survivor curves used in I&M's last two depreciation studies, one of which was fully litigated. It shows that Mr. Cash's proposed curves for these seven accounts is much more in line with what we have previously approved; whereas the curves selected by Messrs. Garrett and Andrew represent significant changes. The OUCC and IG have offered no credible explanation for this significant departure from the currently approved service lives, except to point to data from other utilities. We reject their analyses and find that the survivor curves recommended by Mr. Cash should be approved.

**B. Account 370 (Meters).**

1. I&M. As noted above, the Company is proposing to transition to AMI meters over the next 4 years. Mr. Cash explained that the Company's proposal with respect to Account 370 (Meters) is to recover any undepreciated balance of meters that are retired over the lives of the new AMI meters. He explained that this is consistent with the FERC USOA. Cash Direct, 11-12.

2. OUCC. Mr. Garrett proposed that the currently approved depreciation rate for meters be kept at 6.78%. D. Garrett (Part 2), 47.

3. Industrial Group. Mr. Andrews testified I&M's proposal for Account 370 is different than how it calculated depreciation rates for all other accounts. He testified in light of the accounting under FERC USOA Instruction 10, there was no need to treat meters differently for purposes of setting depreciation rates. Andrews, 14. Based on that approach, he proposed a depreciation rate of 7.67%. *Id.*, 15.

4. Rebuttal. Mr. Cash explained neither Mr. Garrett nor Mr. Andrews had considered the retirement of the existing meters in their proposal. He cited to the NARUC Public Utility Depreciation Practices Manual, which states that changes such as the deployment of AMI meters should be considered in setting depreciation rates. Cash Rebuttal, 20. He explained he could have calculated two different depreciation rates – one for the current meters (recovering over average remaining life of 4 years) and one for the new AMI meters (15 years). He explained that the existing meters also have an expected useful life of 15 years. Using the average age of the existing meters (10.18 years) would produce a remaining life of 4.82 years for the existing meters. *Id.* at 21. He said under his alternative, the rate for existing meters would be 15.66% and for new meters would be 8.13%.

5. Discussion and Finding. Neither Mr. Garrett nor Mr. Andrews account for age of the existing meters and the plan to retire them within the next 4 years, which coincidentally is approximately the average remaining estimated useful life of those meters (4.82 years). Perhaps the alternative approach to have two depreciation rates, one for AMR meters and one for AMI meters would achieve a greater level of accuracy; however, we agree with Mr. Cash, that having one depreciation rate for meters is more simplistic and reaches the correct end point. Accordingly, we approve Mr. Cash's proposed rate for Account 370.

**C. Contingency.**

1. OUCC. Mr. Garrett proposed to exclude contingency from demolition costs that are included in terminal net salvage for purposes of depreciation rates. He testified these costs are unknown and should therefore be excluded. Pub. Ex. No. 11 (Part 2), 22-23.

2. City of Auburn. Auburn witness Rutter also proposed to remove contingency costs from the demolition studies, claiming they were unknown. Rutter, 23.

3. Rebuttal. Mr. Cash testified this Commission has previously approved the inclusion of contingency, specifically the contingency that had been proposed by Sargent & Lundy in Cause No. 44075.

4. Discussion and Finding. This Commission has long recognized the inclusion of a contingency factor in demolition studies for purposes of computing final terminal salvage. As Mr. Cash noted, we approved the inclusion of contingency in Cause No. 44075. *Re Indiana Michigan Power Co.*, Cause No. 44075, p. 105. There, we cited *Northern Indiana Pub. Serv. Co.*, Cause No. 43526, p. 54, 2010 WL 3444546, 264 PUR4th 369, (IURC 8/25/2010), where we similarly approved the inclusion of contingency in the calculation of depreciation. In *NIPSCO*, we cited *PSI Energy*, Cause No. 42359, pp. 70-71, 2004 WL 1493966, 234 PUR4th 1 (IURC 5/18/2004), where we approved the inclusion of contingency. In short, without saying so, Mr. Garrett and Mr. Rutter are asking us to disregard principles that are long established before this Commission. We reject their efforts and accept Petitioner's proposed contingency factor.

**D. Escalation Rates.**

1. OUCC. OUCC Witness Garrett proposed to remove escalation from demolition cost estimates for purposes of computing terminal net salvage. D. Garrett (Part 2), 8. While the Company had used an escalation factor of 2.23%, the inclusion of inflation is inappropriate in Mr. Garrett's judgment. *Id.*, 23. He cited to the methodology for calculating an asset retirement obligation under Financial Accounting Standard 143 ("SFAS 143"), where the future cost of removal is discounted. *Id.*, 24. He also cited to an Oklahoma decision rejecting the use of contingency. *Id.*, 25.

2. Rebuttal. Mr. Cash testified that for purposes of computing terminal net salvage, it is necessary to estimate the cost of demolition at the time it is expected to be incurred. Cash Rebuttal, 8. He explained discounting to present value for purposes of setting depreciation rates would be incorrect because insufficient cost would be recovered over the life of the asset. He further explained customers receive a benefit because customers receive a return on the net salvage component of depreciation expense, which increases accumulated depreciation and reduces rate base. *Id.*, 10. With respect to SFAS 143, Mr. Cash testified Mr. Garrett is confusing the purposes of the required accounting standards with the purposes of recovering the full cost of an asset over its life through straight line depreciation. *Id.*, 11. In response to the citation of an Oklahoma decision, Mr. Cash cited to numerous orders from this Commission specifically approving escalation rates in depreciation calculations. *Id.*, 12-13.



3. Discussion and Finding. Mr. Garrett is urging us to follow the decisions from other states without acknowledging that we have already decided the precise question before us. “We have repeatedly rejected attempts to eliminate or curtail the effects of future inflation when calculating net salvage.” *Indiana-American Water Co.*, Cause No. 44992, p. 10, 2018 WL 2739913 (IURC 5/30/2018). In I&M’s last litigated depreciation proceeding, we found “inflation should be factored into dismantlement cost estimates and [we] reject the OUCC’s proposal to restate costs of removal at present value.” *I&M*, Cause No. 44075, 106. In *PSI*, Cause No. 42359, we made a similar finding: “Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would underestimate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them.” *PSI*, Cause No. 42359, p. 71, 2004 WL 1493966, 234 PUR4th 1. We quoted this language favorably in *NIPSCO*, Cause No. 43526, when we yet again rejected an attempt by the OUCC to remove inflation from dismantlement cost estimates. *Northern Indiana Pub. Serv. Co.*, Cause No. 43526, p. 52, 2010 WL 3444546, 264 PUR4th 369. *NIPSCO* is a particularly apt Order, because SFAS 143 was another depreciation issue in that case. *Id.*, 54. It is troubling that we must repeatedly reject an argument raised by the OUCC; it is more so when the OUCC witnesses cite us to decisions from other states without acknowledging that we have previously rejected their arguments.

#### **E. Interim Retirements.**

1. OUCC. OUCC witness David Garrett proposed to disallow the inclusion of interim retirements in the calculation of depreciation rates. He testified that he was unaware of any Indiana Commission order specifically addressing the issue of interim retirements. D. Garrett (Part 2), 20. He cited to the rejection of recovery of interim retirements in a Texas case involving an AEP affiliate.

2. Rebuttal. Mr. Cash testified that interim retirements are included in a depreciation study to recognize that some components of a generating unit will retire before the plant itself is retired. Cash Rebuttal at 14. He responded to the citation of the Texas Commission decision and explained that it is unreasonable to exclude interim retirements because otherwise, the retired components would be depreciated beyond their service life, shifting the cost of interim retirements to future customers. *Id.*, 16-17. He cited to an earlier decision of this Commission involving I&M specifically finding that interim retirement should be included in the calculation of depreciation rates. *Indiana Michigan Power Co.*, Cause No. 44075 (IURC 2/13/2013).

3. Commission Discussion and Finding. We find that Mr. Garrett is wrong that we have not previously addressed the inclusion of interim retirements in the calculation of depreciation rates. We have actually done so in a case involving I&M depreciation rates, Cause No. 44075, cited by Mr. Cash. There we said: “Interim net salvage relates to retirement costs for property that is retired prior to the final terminal retirement of the property. It is important to include an analysis of interim retirements in a depreciation study since all of the property that is initially placed in service will not last until the final retirement date.” Cause No. 44075, p. 108. We will follow our own precedents rather than a decision from another state with

which an outside consultant may be familiar. Mr. Garrett has provided us no legitimate reason to reject our earlier decisions in this matter.

**F. Rockport.**

1. I&M. Petitioner proposed to change depreciation accrual rates for steam production from 7.52% to 7.77%. The depreciable investment in steam production plant is for the Rockport Generation Plant, as shown in Attachment JAC-1. The estimated retirement date for Rockport Unit 1 is 2028, which is the same retirement date that was assumed for that unit for purposes of the depreciation rates approved in Cause No. 44967. The estimated retirement date for Rockport Unit 2 is 2022, which is the expiration of the lease agreement for that unit. *Id.*, 8. The reason for the change in depreciation rates for steam production is the investment of \$21.7 million in the Rockport plant since the last depreciation study. *Id.*

2. ICC. ICC witness Medine opposed the change in rates for steam production. Her testimony was based upon her opinion that the retirement dates for the Rockport units are caused by the Fifth Modification to the Consent Decree, which modification was due (in her opinion) to Petitioner's failure to comply with a Third Modification to the Consent Decree. She claimed that absent the Fifth Modification, I&M would be under no obligation to retire Rockport Unit 1 in 2028. Medine, 4-16.

3. Rebuttal. Mr. Cash testified that there was no change in the estimated useful life of the Rockport units in his depreciation study presented in this case. He reiterated that additional investment has been made to both Rockport units since the last depreciation study, and the depreciation rates need to be updated to reflect that additional investment. Cash Rebuttal, 4.

4. Discussion and Finding. There is no dispute that the basis for the change in steam production depreciation rates is the additional investment that has been made since depreciation rates were last approved. There is no change to the estimated useful life of the Rockport units in this case. Further, Ms. Medine did not offer an alternative estimated useful life for the Rockport units. She also does not object to the inclusion of the additional investment in the calculation of the depreciation accrual rates for steam generation. As a result, we reject Ms. Medine's arguments and find that the proposed rates for steam production should be approved.

**G. Rockport Enhanced DSI.**

1. Joint Municipal Group. Constance T. Cannady testified on behalf of the Joint Municipal Intervenor with respect to the depreciation accrual rate for Petitioner's proposed enhanced DSI project at the Rockport plant. She testified that Petitioner appears to be is proposing a 12% depreciation rate for the enhanced DSI system on Unit 1 and a 20% rate for the system on Unit 2. She disagreed-argued that I&M's proposed depreciation rate that which allowed for recovery over a period of less than 10 years with this proposal and testified that the investment should be recovered over no less than ten years pursuant to is not consistent with the provisions of Indiana Code § 8-1-2-6.7(b) and should be disallowed. Cannady, 3-4, 11-18. Ms. Cannady also noted that a 10 year depreciation period for enhanced DSI is similar to the DSI depreciation period approved for I&M in Cause No. 44871. Ms. Cannady testified that because



the door is still open to a lease extension, the Company is “having their cake, and eating it too” by seeking accelerated depreciation on a plant that may or may not actually retire. *Id.* at 15.

2. Rebuttal. ~~Mr. Cash noted that Ms. Cannady is mistaken concerning the Company’s proposal.~~ Mr. Cash noted on rebuttal that Ms. Cannady ~~He said she has~~ confused the depreciation rate for the enhanced DSI project with the rate for the selected catalytic reduction system (“SCR”). He explained the 12% and 20% rates are the proposed rates for the SCR. Cash Rebuttal, 4. He testified that no depreciation rate was calculated specifically for the enhanced DSI project. *Id.*, 4-5. Accordingly, he ~~said~~ argued that the general depreciation rates approved for Rockport would apply. *Id.* On cross-examination, Mr. Cash confirmed that I&M is continuing to assess all options with regard to the Rockport 2 lease. Tr. B 36-37.

3. Discussion and Finding. I&M caused confusion when it did not propose any depreciation rates specific to the enhanced DSI project in the Company’s Direct Testimony, and thus the parties had to wait for the Company’s rebuttal in order to understand how the project would be depreciated. It appears that Ms. Cannady is confused about the depreciation rates being proposed. Petitioner did not propose the rates to which Ms. Cannady objects. The enhanced DSI project is included in the total Rockport Unit 2 investment and the same depreciation rates that are approved for Rockport Unit 2 will apply to the enhanced DSI project. Cash Rebuttal, 5. Furthermore, we disagree with Ms. Cannady’s contention (p. 15) that the minimum recovery prescribed by Indiana Code § 8-1-2-6.7(b) is ten years. This statutory provision provides for depreciation of certain technology “over a period of not less than ten (10) years or the useful economic life of the technology, whichever is less . . . ”. I&M confuses the economic useful life of the enhanced DSI technology with the remaining life of the Rockport 2 lease. Simply because the lease will expire in less than ten years does not mean that the economic useful life of the technology is less than ten years. The Commission has addressed depreciation rates for Rockport in prior cases, but we have not addressed a situation where the proposed depreciation life of a generating asset is less than ten years because it is tied directly to the termination of a contractual lease obligation, rather than the economic useful life of the asset. I&M has not provided any evidence showing that the stand alone economic useful life of the enhanced DSI project is less than ten years. We find it illogical to approve a DSI depreciation rate for Rockport of 10 years in Cause No. 44871, and subsequently find that another DSI project has an economic useful life of less than ten years at the very same generating unit. Accordingly, we find Ms. Cannady’s objection should be rejected and the Company’s proposal that a ten year depreciation rate for the enhanced DSI project should be approved, consistent with the requirements of Indiana Code § 8-1-2-6.7(b).

## **8. Fair Rate of Return.**

A. I&M. Mr. Hevert said his analyses indicate that I&M’s cost of equity (“COE”) currently is in the range of 10.00 percent to 10.75 percent. Hevert Direct, 2. He testified based on the quantitative and qualitative analyses discussed throughout his Direct Testimony, 10.50 percent is a reasonable estimate of I&M’s cost of equity.

In developing his recommendation Mr. Hevert relied on several widely accepted methods: (1) the Constant Growth Discounted Cash Flow (“DCF”) model; (2) the traditional and empirical forms of the Capital Asset Pricing Model (“CAPM”); and (3) the Bond Yield Plus Risk

Premium approach. Hevert Direct, 3-4. Mr. Hevert testified his analyses recognize that estimating the COE is an empirical, but not entirely mathematical exercise; it relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied.

He said no single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application, and in interpreting their results. He stated therefore, that the results of each return on equity (“ROE”) model must be assessed in the context of current and expected capital market conditions, and relative to other appropriate benchmarks. Hevert Direct, 4. Mr. Hevert explained that since 2014, the DCF model has produced results consistently and meaningfully below authorized returns and explained that the model’s underlying structure and assumptions are not compatible with the recent capital market and economic environment. Hevert Direct, 5, 8. Mr. Hevert testified we should carefully consider the range of results the DCF model produces in arriving at ROE recommendations. *Id.*, 9.

He discussed his proxy group and explained his recommendation takes into consideration the risk factors associated with: (1) the Company’s generation portfolio and related environmental regulations; (2) customer concentration; and (3) the Company’s planned capital expenditures and the effect, if any, of certain regulatory mechanisms. In addition to the methods noted above, Mr. Hevert calculated the costs of issuing common stock (that is, “flotation” costs), and considered evolving capital market and business conditions, including changes in Federal Reserve monetary policy and increases in current and projected government bond yields. He stated although those factors are very relevant to investors, their effect on the Company’s Cost of Equity cannot be directly quantified. Therefore, he said although he did not make explicit adjustments to his ROE estimates, he considered those factors in determining where the Company’s cost of equity falls within the range of analytical results. Hevert Direct, 3-4.

As to I&M’s proposed capital structure for the test year ending December 31, 2020, which (on the basis of investor-supplied capital) includes 46.80 percent common equity and 53.20 percent long-term debt, Mr. Hevert concluded the Company’s proposal is consistent with the capital structures that have been in place over several fiscal quarters at comparable operating utility companies. Hevert Direct, 57. Given the consistency of its proposal with similarly situated utility companies, he concluded the Company’s proposed capital structure is reasonable and appropriate. Regarding the cost of debt, Mr. Hevert said he understands that the Company’s projected weighted average cost of long-term debt at the end of the test year is 4.54 percent, which he believes is reasonable and appropriate. *Id.*, 3, 56-58.

**B. OUCC.** Mr. D. Garrett testified an analysis of an appropriate awarded ROE for a utility should begin with a reasonable estimation of the utility’s cost of equity capital. He explained in estimating the Company’s cost of equity, he performed a cost of equity analysis on a proxy group of utility companies with relatively similar risk profiles. Based on this proxy group, he evaluated the results of the two most common financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. He stated applying his chosen inputs and assumptions to these models indicates that the Company’s estimated cost of equity is about 6.5%. D. Garrett (Part 1), 10-11; also Garrett, 29-83. Mr. Garrett recommended however,

the Commission award an ROE of 9.1%, which he said is within a reasonable range of 9.0% – 9.5%. D. Garrett (Part 1), 11.

Mr. Garrett criticized Mr. Hevert's terminal growth rate, equity risk premium, bond yield plus risk premium model, and discussion of capital market environment. D. Garrett (Part 1), 14-19. He discussed the legal standards and awarded returns. *Id.*, 20-29.

**C. Industrial Group.** IG witness Gorman used the following models to estimate I&M's cost of common equity: (1) a constant growth DCF model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a CAPM.

Based on his analyses, IG witness Gorman recommended I&M's current market cost of equity to be no higher than 9.00%. Gorman, 93. He testified a return on common equity of 9.00% is the high-end of his estimated range of 8.50% to 9.00%, which he said reflects the current low capital market cost for a utility with risks similar to I&M. He said his return on equity estimates reflect observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the electric utility industry and the market's demand for utility securities. *Id.*, 94. He said his recommended overall rate of return will support an investment grade bond rating for I&M. *Id.*

IG witness Gorman said he found the Company's proposed capital structure weight is reasonable and therefore produces an overall cost of capital which is appropriate for rate-setting purposes and took no exception to the Company's embedded cost of debt for 2020. Gorman, 61.

Mr. Gorman testified Mr. Hevert's analyses produce excessive results for various reasons, including the following: 1) his constant growth DCF results are based on unsustainably high growth rates; 2) his CAPM is based on inflated market risk premiums; 3) his empirical CAPM is based on a flawed methodology; and 4) his Bond Yield Plus Risk Premium studies are based on inflated utility equity risk premiums. Gorman, 98-128.

**D. Other Intervenors.** Walmart witness Chriss did not perform a cost of equity analysis but recommended the Commission closely examine the ROE in light of customer impact, use of the future test year and recent ROE decisions approved by the Commission and nationwide. Chriss, 4, 7-14. 39 North witness Cearley also did not perform a cost of equity analysis but recommended the Commission recognize I&M's customer satisfaction scores in adopting a return. Cearley, 8-9.

**E. Rebuttal.** Mr. Hevert explained there are several methodological, theoretical, and practical reasons why the Opposing ROE Witnesses' recommendations are unduly low. He said because the Opposing ROE Witnesses give meaningful weight to their DCF-based results, it is not surprising that their recommendations fall well below currently authorized returns. He added given their common reliance on the DCF method, it also is not surprising that the Opposing ROE Witnesses' recommendations generally fall within a narrow range. Mr. Hevert stated the fact that the Opposing ROE Witness recommendations are similar does not mean their approaches and conclusions are reasonable. Hevert Rebuttal, 4-5.

He stated in some cases, the Opposing ROE Witnesses' recommendations stem from unreasonably low DCF estimates, which themselves are the result of tenuous assumptions. He said there is no reasonable basis to assume the current volatile capital market environment will remain in place in perpetuity. Mr. Hevert testified we cannot conclude the recent levels of utility valuations are due to a fundamental and permanent change in the risk perceptions of utility investors, as the Opposing ROE Witnesses' recommendations assume. He said those valuation levels are more likely related to the "reach for yield" that often occurs during periods of low Treasury yields. Hevert Rebuttal, 3.

Mr. Hevert also explained certain of the Opposing ROE Witnesses' recommendations are fundamentally disconnected from their own analyses and conclusions, and are far removed from observable and relevant data. Hevert Rebuttal, 4. He said although Mr. Gorman suggests the Cost of Equity has fallen to a level that supports his recommendation, observable data does not support this position. Hevert Rebuttal, 5.

Mr. Hevert stated the Opposing ROE witnesses are not consistent with returns authorized by the Commission and elsewhere in the U.S. He explained if the Commission were to authorize a return of 9.10 percent or lower as the Opposing ROE Witnesses recommend, it would represent a significant departure from returns previously authorized by the Commission. Hevert Rebuttal, 5-6; Chart 1.

Mr. Hevert testified the financial community carefully monitors utility companies' financial conditions, both current and expected as well as the regulatory environment in which those companies operate. He said a consequence of an authorized ROE in the range of the Opposing ROE Witnesses' recommendations would be to increase investors' perceptions of regulatory risk. Hevert Rebuttal, 6.

Mr. Hevert also noted the Company expects its Network Integration Transmission Services ("NITS") costs to increase by about \$48 million in 2021, just one year beyond the Test Year in this Cause and pointed out Mr. Williamson's statement that absent the ability to recover the increased NITS cost, the Company's earned Return on Common Equity would fall by about 1.90 percentage points (190 basis points). Hevert Rebuttal, 94. Mr. Hevert stated that because operating cash flow is directly related to income, the earnings erosion brought about by the inability to recover increased NITS costs will put downward pressure on I&M's financial profile, increasing the financial community's perceptions of the Company's risk. Mr. Hevert said the combination of the Opposing witnesses' unduly low ROE recommendations and the increased likelihood of under-earning absent the timely recovery of increased NITS costs suggests returns that are far too low to be considered reasonable. *Id.*, 94-95.

Mr. Hevert concluded based on the analyses discussed throughout his direct and rebuttal testimony, the reasonable range of ROE estimates is from 10.00 percent to 10.75 percent, and within that range, 10.50 percent is a reasonable and appropriate estimate of I&M's Cost of Equity. *Id.*, 96.

**F. Discussion and Finding.** The rate of return for a utility must be comparable to the return on investments in other enterprises having corresponding risks, sufficient to assure confidence in the financial integrity of the utility, maintain support of the

utility's credit, and attract capital. *Bluefield Waterworks & Improvements Co. v. Pub. Service Comm. of West Virginia*, 262 U.S. 679, 43 S.Ct. 675 (1923); *Federal Power Comm. v. Hope Natural Gas. Co.*, 320 U.S. 591, 64 S.Ct. 281 (1944).<sup>9</sup>

In order to meet the requirements set forth in *Bluefield* and *Hope*, the parties proposed various returns using the DCF model and other methods as bases for their positions. Mr. Hevert's analysis produced a range of 10.0% to 10.75%. He recommended the Commission adopt a cost of common equity of 10.50%. Mr. Garrett's estimated cost of equity is about 6.5%. He recommended a return on common equity of 9.10% based on a range of 9.00% to 9.50%. Mr. Gorman's analysis produced a range of 8.50% to 9.00%. He recommended a COE of 9.00%.

The Commission recognizes that the cost of equity cannot be precisely calculated and estimating it requires the use of judgment. Due to this lack of precision, the use of multiple methods is desirable because no single method will produce the most reasonable result under all conditions and circumstances. In particular, substantial record evidence indicates that in the current capital market environment Constant Growth DCF-based models should be viewed with caution, because they do not adequately reflect changing capital market conditions and high levels of instability, whereas Risk Premium-based methods directly reflect such changes and measures of risk. We note that the OUCC and Intervenor recommendations are inconsistent with recent ROE decisions approved nationwide for investor-owned electric utilities. While we do not base our conclusion on national averages, this information illustrates the dramatic departure from Commission and other precedent these parties urge the Commission to adopt. Additionally, financial strength is necessary for a utility to attract capital at a reasonable cost in order to make the investments necessary to for the utility to fulfill its service obligations at a reasonable cost. In addition to it constituting a significant change in Indiana utility regulatory policy, the significant decrease in ROE recommended by the OUCC and Intervenor would likely be viewed as a negative development, putting downward pressure on the Company's credit ratings. See Hevert Rebuttal, 41-43.

The Commission has considered the analytical results based on a proxy group of electric utilities, as well as the risk factors associated with: the Company's generation portfolio and environmental regulations; customer concentration; the Company's planned capital expenditures and the effect, if any, of certain regulatory mechanisms; and the costs of issuing common stock. Furthermore, as shown by Mr. Lucas, I&M's business and residential customer satisfaction scores have increased which is notable given the evolving needs and expectations of customers. Lucas Rebuttal, 32-33. These risk factors, however, are mitigated by the number of trackers that I&M has in place, which serve to remove risks of uncertainty that the Company would otherwise face. As we stated in Indianapolis Power & Light Co., Cause No. 44576, p. 41 (IURC March 16, 2016):

Trackers that adjust rates for incremental investments or for costs that are nearly certain to be increasing serve to adjust the base line earnings for post rate case changes and address issues primarily associated with regulatory lag. Trackers that adjust rates for cost changes that are more unknown and that are equally likely to decrease or increase address the

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<sup>9</sup> See also *Re Indianapolis Power & Light Co.*, Cause No. 44576, p. 41 (IURC 3/16/2016).



risk of volatile earnings results. The general effect of these trackers reduces the uncertainty of earnings that an investor can expect.

Having taken into consideration the foregoing factors and observable market data reflected in the record, the Commission finds that a ROE in the range of 10.00 percent to 10.75 percent represents the range of returns required by equity investors under current and expected market conditions. When considering the challenges faced by the Company, we further find and conclude that a 10.5% ROE would be is fair and reasonable absent other circumstances present here.

However, as we have previously noted:

a utility's operational and financial performance were appropriate considerations in determining a utility's cost of equity.... The Commission has a unique role in regulating its jurisdictional utilities, which at times requires us to send a clear and direct message to utility management concerning the need for improvement in the provision of its utility service. Our determination of the authorized cost of common equity capital can be a very direct means to incent improved service.

Indianapolis Power & Light Co., Cause No. 44576, at 44 (IURC March 23, 2016) (quoting Northern Indiana Public Service Co., Cause No. 43526, at 32 (IURC Aug. 25, 2010)). As discussed in more detail below, the evidence on the record before us indicates the Company failed to prudently manage its wholesale contracts with IMMUDA customers by not taking advantage of an opportunity provided by FERC to add exit fees to its wholesale contracts and avoid the situation of stranded costs that we now face today. What's more, the Company's failure dates back almost 23 years but is just now coming to light, despite repeated opportunities for the Company to come forward and seek possible regulatory solutions.

In order to provide an appropriate message to I&M management, the Commission finds that an adjustment to the ROE is warranted. As noted above, the unadjusted cost of equity of 10.5% represents the otherwise appropriate cost of equity for I&M. The low end of the range recommended by I&M's own witness, Mr. Hevert, is 10.0%, which we find to be representative of an appropriate adjustment.

**G. Overall Weighted Cost of Capital.** Mr. Hevert's testimony regarding the Company's capital structure was not challenged. Having reviewed his testimony and that of Mr. Gorman we find the Company's Test Year capital structure is consistent with industry practice and supports I&M's financial integrity. Based on these findings and after having given effect to the ROE authorized above, the Commission finds that Petitioner's capital structure and weighted cost of capital is as follows:

<u>Description</u>	<u>Total Company Capitalization</u>	<u>Percent of Total</u>	<u>Cost Rate</u>	<u>Weighted Average Cost of Capital</u>
Long Term Debt	\$ 2,926,531,185	42.69%	4.54%	1.94%
Common Equity	\$ 2,574,496,077	37.55%	10. <del>50</del> 0%	3. <del>76</del> 94%

Customer Deposits	\$ 37,972,608	0.55%	2.00%	0.01%
ACC. DEF. FIT	\$ 1,297,621,545	18.93%	0.00%	0.00%
ACC. DEF. JDITC	\$ <u>18,960,268</u>	<u>0.28%</u>	7.33%	<u>0.02%</u>
Total	\$ <u>6,855,581,684</u>	100.00%		<u>5.7291%</u>

The Commission ~~accepts~~ authorizes I&M's ~~proposal~~ to establish its authorized net operating income by multiplying the above overall weighted average cost by the original cost Test Year rate base.

## 9. Disputed Test Year Revenue.

### A. Customer Count Adjustment.

1. OUCC. Mr. Watkins stated that, based on informal discussions with I&M, it was determined there was an error in developing the forecasted test year billing determinants as it relates to the number of customers and number of bills. Watkins, 49. He explained the Company corrected its forecasted billing determinants by rate schedule, which has the effect of increasing the number of customer bills for most rate schedules, which in turn, increases customer charge revenue at current rates. *Id.*

2. Rebuttal. Mr. Nollenberger stated Mr. Watkins used the updated Test Year number of bills to re-compute forecasted Test Year revenues, resulting in an increase to forecasted Test Year revenues of \$3,758,305. He said I&M agreed with this change to Test Year revenues. Nollenberger Rebuttal, 42.

3. Discussion and Finding. We find the use of the updated Test Year number of bills to be appropriate. We note that while this update does not change the Company's overall revenue requirement, it does reduce the revenue deficiency by the amount of the correction.

## 10. Disputed Test Year Operation and Maintenance ("O&M") Expenses.

### A. Cook 316(b).

1. I&M. Messrs. Williamson and Lies supported the Company's proposal with respect to costs incurred to study the Cook Nuclear Plant's cost of compliance with Section 316(b) of the Clean Water Act, which costs the Company has deferred. Through these studies, the Company was able to determine that no additional capital costs are needed to comply with this federal environmental requirement. Williamson Direct, 29; Lies Direct, 24-25. The Company proposes to include the deferred costs in rate base and amortize them through rates over 15 years, which reasonably approximates the remaining life of the Cook Plant. Williamson Direct, 29.

2. OUCC. OUCC Witness Eckert testified the Commission should reject I&M's deferral of these costs. He claimed I&M's rates already recover an embedded level of compliance cost recovery and I&M should have sought deferral authority in prior rate cases. Eckert, 15-16, 20.

3. Rebuttal. I&M witness Ross explained the Cook 316(b) costs were properly recorded to Account 107, Construction Work in Progress, in accordance with the FERC USOA and in anticipation of a capital project. He said when it was determined it was uncertain as to whether I&M would be required to construct a property asset, I&M properly reclassified the Cook 316(b) costs to Account 183 for Preliminary Survey and Investigation Charges, which is the account where costs of preliminary studies of the feasibility of capital projects are recorded. Ross Rebuttal, 16. He said, as also supported by Mr. Lies in his direct testimony, I&M does not believe the result will be I&M's construction of a capital asset. Rather than expensing them, Mr. Ross stated the costs should be recorded in accordance with ASC 980, Regulated Operations, to Account 182.3 based upon the prudence of conducting the study and past precedent of recovery of similarly incurred costs related to Cook. *Id.*, 17.

I&M witness Lies responded to Mr. Eckert's testimony that the 316(b) costs were embedded in the calculation of base rates in Cause No. 44075. He said the 316(b) Project costs are not similar to the Fire Suppression System costs that were expensed and approved in Cause No. 44075. He explained the Fire Suppression System costs of about \$1.7 million were related to an O&M project, not a capital project. He added I&M expects to regularly incur O&M costs to comply with emerging requirements that are relatively limited in scope. He said the 316(b) Project costs, on the other hand, were incurred cumulatively over the course of ten years in anticipation of a major capital project that itself also would have taken several years to complete, and which would have been necessary to ensure the on-going operation of the Cook Plant. He noted the possible outcome of the 316(b) study could have been the installation of cooling towers costing upwards of \$1 billion. Lies Rebuttal, 2-3. He added, as appropriate for any possible capital project of this scope, studies were used to determine the path forward. He said the 316(b) studies allowed I&M to avoid a major capital project and this outcome was a positive outcome for I&M's customers. *Id.* at 3.

4. Discussion and Finding. There is no dispute and we find that the 316(b) costs were prudently incurred. By incurring the study costs, I&M has avoided a substantial additional compliance cost and this benefits customers. It is appropriate to reflect the study cost in rates as it has reduced the ongoing cost of service. We find the evidence persuasive that costs such as these have not been recovered through I&M's existing rates. We agree with Mr. Lies that these costs are significantly different from the Fire Suppression System costs at issue in Cause No. 44075. As to the OUCC's argument that I&M should have sought authority to defer these costs as a regulatory asset, GAAP does not require such authorization. The question for recording a regulatory asset under ASC 980 is probability of recovery (Ross Rebuttal, 17), which may come from a Commission order, but such an order is not the only means. For instance, rate case expense is deferred without a Commission order in advance. The 316(b) costs are akin to the baffle bolts at issue in Cause No. 44075 – they are infrequently incurred but they benefit the Cook Unit over the balance of its remaining life. Like the baffle bolts, we will authorize the costs to be amortized over a period of 15 years which is representative of the remaining life of the Cook Units, with the unamortized balance included in rate base.

## **B. Customer Assistance Programs.**

1. I&M. Mr. Lucas testified I&M worked with a number of stakeholders in 2018 to establish four specific customer assistance programs: (1) Energy Share



Pilot Program; (2) Low Income Weatherization; (3) Neighbor to Neighbor Pilot Program; and (4) Low Income Arrearage Forgiveness Pilot Program. Lucas, 29. He provided an update on each pilot and explained I&M is proposing to continue each of these programs. In addition, he said I&M is proposing an Income Qualified Safety & Health Pilot Program to address safety and health issues that prevent the completion of an income-qualified energy audit. Lucas, 29-34.

2. OUCC. Mr. Haselden recommended the Commission deny I&M's request to include the costs of the customer assistance programs in the cost of service. He stated these programs exceed the scope of a utility's operational obligation and are not reasonable and necessary. He said I&M presented no compelling evidence as to why it is appropriate to include the expense to offer these programs at a cost to ratepayers. Pub. Ex. 6 at 3-7.

3. Intervenors. IG witness Gorman stated that funds for customer assistance pilots should come from shareholders, not ratepayers. Gorman, 39. CAC-INCAA witness Olson provided an update on the Low Income Arrearage Forgiveness Pilot Program and said CAC-INCAA is generally pleased with this pilot program with one exception and recommended I&M go back and continue to work with stakeholders to coordinate this program with the Neighbor to Neighbor Pilot Program. Olson, 13-18. Mr. Olson supported I&M's proposal regarding the Energy Share Program, the Low Income Weatherization Program, and the Income Qualified Safety & Health Pilot Program and appreciated the Company's commitment to these programs. Olson, 18-19. South Bend witness Dorau stated South Bend generally supports the expansion of I&M's customer assistance programs and is enthusiastic about I&M's proposed Income Qualified Safety & Health Pilot Program, which she said will make a significant improvement in the long-term stability of customers receiving this investment. Dorau Direct, 10-12. Her cross-answering testimony elaborated on her view as to the benefits of these customer assistance programs. Dorau Cross-Answering, 7-8.

4. Rebuttal. Mr. Lucas explained the proposed initiatives are designed to address and gather additional information as to whether and how customer assistance programs can improve the longer term cost of providing service. Lucas Rebuttal, 19. He explained the connection between these pilot programs and I&M's cost of service and said it would be premature to categorically rule out these programs as Mr. Haselden does. *Id.*, 19-20. He stated I&M conducted the collaborative process for all customer assistance programs in good faith and has incorporated a number of substantive components proposed by the CAC. *Id.*, 20-21.

5. Discussion and Finding. I&M proposes to continue several customer assistance programs agreed to and approved in its last rate case, along with a new program to assist income-qualified customers in addressing safety and health issues that prevent the completion of a home energy audit. Several parties testified in support of I&M's customer assistance programs.

The OUCC and IG opposition appears based not on the merits of the programs, but on their relation to the provision of utility service. We begin our discussion by reminding that these are pilot programs which are designed to gather information as to whether programs such as these can help reduce the long term cost of providing service. The record shows the customer assistance programs will provide customers with assistance, education, and tools to help the financial resiliency of customers who are challenged to pay their electric bill. Lucas Rebuttal, 19.

As Mr. Lucas explained, in doing so, I&M and its partners are reducing costs associated with credit and collections, disconnecting and reconnecting customers, and avoiding potential write-offs due to lack of payment. Because these costs are reflected in the revenue requirement, the pilot programs may, in turn, result in larger scale programs that will help to maintain I&M's overall cost of providing service, for the benefit of all of I&M's customers. I&M's pilots are designed and intended to explore the connection between customer assistance programs and the cost of providing utility service. The OUCC and IG have jumped to the conclusion that such programs will be unsuccessful in achieving the desired goals without first studying the information the pilot programs are intended to provide. The investment is small, yet the potential benefits are great – especially if the pilots ultimately result in larger scale programs that can help some of the customers most in need while at the same time lowering overall cost of service. We find the cost of these proposed pilots is not excessive and is reasonably necessary for the provision of electric service. Accordingly, we reject the OUCC and IG's proposed disallowance of these costs and further find that these pilots should be approved.

### C. Economic Development.

1. I&M. Mr. Lucas discussed the importance of economic development and the Company's ongoing support of economic development in its service area. Lucas Direct, 18-19. He explained increased load from economic development benefits all I&M customers by spreading the fixed costs that are necessary to maintain the electric system, ultimately lowering customer rates. Lucas Direct, 19. Mr. Lucas described the Economic Impact Grant ("EIG") Program included in the settlement agreement in Cause No. 44967 and the Company's proposal to reflect \$137,500 in the Test Year revenue requirement to continue the third component of the EIG after rates go into effect in this case. *Id.* at 21. He identified challenges to include the availability of a skilled workforce and need for an inventory of desirable existing buildings, available for sale or lease, and said these are critical to attracting new businesses to the region. Lucas Direct, 21-22. He added the current building inventory in I&M's service territory is critically low and, as a result, the area has been unable to compete for some new investments. *Id.* at 22.

Mr. Lucas discussed two pilots the Company proposes to use to address these challenges. The Apprenticeship and Training pilot program would focus on workforce development over a two-year period at a cost of \$350,000 per year. Lucas Direct, 23-27. The Building Development pilot would support the development of "spec" buildings over a two-year period at a cost of \$150,000 per year. Lucas Direct, 24-27.

2. OUCC. Mr. Haselden recommended any funds used for economic development activities should not be included in I&M's cost of service. Haselden, 4. He said while availability of a well-trained workforce and developable sites is valuable to economic development, these kinds of programs are not necessary for the provision of energy utility service, and relate to issues that state and local economic development agencies are intended to address. *Id.*, 4-5.

3. Intervenors. Industrial Group witness Phillips and Joint Municipal Group witness Mancinelli also recommended any funds used for economic development activities should not be included in I&M's cost of service. Phillips, 27; Mancinelli, 58. South

Bend, the Joint Municipal Group and 39 North all suggested modifications to I&M's proposed economic development programs. Dorau Direct, 21-23; Mancinelli, 57-59; Cearley, 11-21. The Joint Municipal Group and 39 North also raised concerns regarding the administration of I&M's existing economic development programs. Fasick, 5-14; Cearley, 12. consistency and prudence with which I&M has managed and administered the EIG program established in the Settlement Agreement, as approved by the Commission, in Cause No. 44967. Fasick, 5-14; Cearley, 12. Specifically, Mr. Fasick expressed frustration that I&M has been creating a moving target for eligibility requirements, resulting in what Fort Wayne contends is unreasonably withholding approval of an eligible application from Fort Wayne for a new water pressure station. Fasick, 9-12. Ms. Dorau's cross-answering testimony reiterated the importance of economic development support to municipalities seeking to maintain and grow their communities and viewed I&M's pilot programs as modest investments in developing I&M's expanded portfolio of economic development efforts. Dorau Cross-Answering, 6-7.

4. Rebuttal. Mr. Lucas explained why he disagreed that I&M's economic development program costs should be removed from the revenue requirement used to establish rates in this proceeding. He testified that customer load continues to be flat to declining and it is becoming exceedingly difficult to manage customer rates by managing costs. Lucas Rebuttal, 8-9. He said economic development is arguably one of the best tools the Company has to manage the cost of electricity for its customers. *Id.*, 8. He reiterated I&M has worked with local partners to bring over 4,500 jobs and nearly \$900 million of capital investments to I&M's service area over the past five years. *Id.*, 8-9. He added in many of these opportunities, safe, reliable, and reasonable electric service was a significant consideration in attracting new companies to the area. He said these economic development successes benefit all of I&M's customers by spreading I&M's fixed costs over a broader base of customers. *Id.*, 9.

Mr. Lucas said I&M appreciates the constructive feedback from the City of South Bend on the economic development programs proposed in this case and said I&M is open to including the energy and construction trades into the Workforce Development pilot program. Lucas Rebuttal, 11. He also said I&M would be willing to incorporate modernizing existing commercial buildings or new commercial construction on an infill site as part of the Building Development pilot so long as they meet all of the eligibility requirements. *Id.* Mr. Lucas disagreed with Mr. Mancinelli's proposal to expand the existing EIG grant and have none of the costs included in the revenue requirement. He said Mr. Fasick's recommendation is based on a misunderstanding of I&M's proposal and runs counter to the ratemaking principle that reasonable and necessary costs of providing service should be recognized in rates. *Id.*, 12-13. That said, he explained I&M sees value in the EIG program and proposes to continue to make available \$137,500 per year of funding for the EIG. *Id.*, 12.

Mr. Lucas also responded to concerns raised by Mr. Fasick regarding I&M's administration of the existing EIG program. He said I&M is managing the program consistent with the eligibility requirements for Qualifying Projects and strongly disagreed with the notion that I&M is not administering the program correctly. Lucas Rebuttal, 14. He Mr. Lucas testified since the start of this program, I&M has conducted two Economic Development Stakeholder meetings with local economic development organizations and municipal staff responsible for economic development activities. He said in both of these meetings I&M discussed the EIG program, the application process, and encouraged all attending to participate in the program.

Additionally, he noted I&M has conducted a number of one-on-one meetings with the Joint Municipals and economic development organizations to discuss the EIG program and issued multiple communications encouraging participation. *Id.*, 14-15. He testified much of the concern raised by Mr. Fasick's testimony regarding Fort Wayne's application for EIG funds appears to be based on a disagreement over the purpose and goal of the EIG program. *Id.*, 17. He said the intent of the EIG program was not for one utility to pay for the infrastructure project of another utility, which is the basis for Fort Wayne's application. He said I&M had multiple conversations with Mr. Fasick regarding this project and attempted to provide guidance on the necessary components of the application for the project to be approved. *Id.* He said I&M looks forward to working with Fort Wayne on any future applications that will benefit all I&M customers by promoting economic development opportunities in the I&M service area. *Id.*, 18.

On cross-examination, Mr. Lucas took the position that I&M has discretion to develop and impose additional eligibility requirements for Qualifying Projects other than what the Settlement Agreement established. Tr. G-5. Although he believes the Settlement Agreement allowed I&M to establish additional "guidelines," he could not identify any written guidelines other than I&M's EIG application and possibly handouts during a handful of stakeholder meetings. Tr. G-20–G-21. However, Mr. Lucas did not personally participate in those meetings and could not say for sure whether any such handouts even existed. *Id.* He also could not confirm whether I&M sought any stakeholder involvement when it developed its "guidelines" for administering the EIG funds. Tr. G-7.

Mr. Lucas testified much of the concern raised by Mr. Fasick's testimony regarding Fort Wayne's application for EIG funds appears to be based on a disagreement over the purpose and goal of the EIG program. ~~Id.~~ Lucas Rebuttal, 17. He said the intent of the EIG program was not for one utility to pay for the infrastructure project of another utility, which is the basis for Fort Wayne's application. ~~He~~ *Id.* However, on cross-examination he admitted that this eligibility "requirement" was not found in the Settlement Agreement, nor in any purported guidelines that I&M unilaterally developed. Tr. G-18–G-20. Mr. Lucas said I&M had multiple conversations with Mr. Fasick regarding ~~this~~ Fort Wayne's project and attempted to provide guidance on the necessary components of the application for the project to be approved. ~~Id.~~ Lucas Rebuttal, 17. He said I&M looks forward to working with Fort Wayne on any future applications that will benefit all I&M customers by promoting economic development opportunities in the I&M service area. *Id.*, 18.

During his cross-examination, Mr. Lucas was confronted with 39 North's and Fort Wayne's separate applications for water facilities projects that were each designed to increase water pressure service to retain and attract new commercial and industrial development in their respective areas. Tr. G-11–G-14; Jt. Municipals' Ex. CX-7 and CX-8. In his testimony comparing the two applications, Mr. Lucas could not provide a cogent reason why I&M had approved 39 North's application, but had denied Fort Wayne's application. Tr. G-21–G-34. Mr. Lucas did note that I&M's approval of 39 North's application was based on "one identified industrial site in I&M's service territory," but he also admitted on cross-examination that Fort Wayne's application identified 15 sites totaling 91 acres zoned for commercial and industrial use within I&M's service territory that would benefit from Fort Wayne's new water pressure station.

Tr. G-24, G-39-40; see also, Jt. Municipals' CX-9. He provided no explanation why the one industrial site identified in 39 North's application was sufficient to support I&M's approval, but the 15 sites identified in Fort Wayne's application was not.

With respect to Mr. Cearley's concerns, Mr. Lucas testified that 39 North has submitted five applications under the EIG program. ~~Id.~~ Lucas Rebuttal, 16. He said three applications were approved for funding and the other two applications did not meet the eligibility criteria. He said I&M has provided 39 North feedback on both applications that did not meet the eligibility criteria. He reiterated I&M is committed to managing the EIG program in an objective and reasonable manner consistent with the terms of the Settlement Agreement approved in Cause No. 44967. *Id.*

5. Discussion and Finding. "The Commission has long recognized the importance of economic development programs and supported efforts by Indiana utilities to attract additional investments within their service territories through economic development rates." *Re Indiana Michigan Power Co.*, Cause No. 43953 (IURC 2/23/2011) at 4. The Commission has stated "it is our intent to foster quality economic development whenever possible." *Id.*, quoting *In re Indiana Michigan Power Co.*, Cause No. 41366 at 7 (IURC 10/13/1999); see also *Re Northern Indiana Pub. Serv. Co.*, Cause No. 42348 (IURC 3/26/2003) at 4-5 (explaining economic developments benefits utility customers and the state).

Before addressing any of the proposed economic development programs from I&M, we first must address the concerns of Mr. Cearley and Mr. Fasick regarding I&M's administration of the existing EIG program. I&M's Case-in-Chief requested authority to continue the EIG program and include it in its cost of service. Lucas Direct, 21. I&M's ability to consistently and prudently administer the EIG program established in Cause No. 44967 is highly relevant to our consideration of its request in this proceeding to continue the EIG program but include its cost in rate base. Given that these issues have been fully litigated in this Cause, to require the Commission to open an investigation on its own motion, or the parties to file a new proceeding, simply to present the same evidence already heard in this proceeding, would be a waste of both the parties' and the Commission's resources.

Turning then to the merits of Mr. Fasick's and Mr. Cearley's concerns, we find them to be valid. Comparing I&M's disparate treatment of the applications from 39 North for a water tower and Fort Wayne for a water pressure station, both of which were designed to increase water pressure to retain and attract new commercial and industrial development, we find that I&M did not administer the EIG program established in Cause No. 44967 in a consistent and even-handed manner. Section 17.7(b) of the Settlement Agreement allocated funds to each of the Joint Municipals, including Fort Wayne, to support Qualifying Projects "subject to the review and approval of I&M, which approval shall not be unreasonably withheld." (Emphasis added). The Company's argument that it should not provide grant funding related to the provision of utility service by other providers appears to be simply pretext. The record demonstrates that Fort Wayne's application for its allocated portion of EIG funds was not materially different than 39 North's application, and in any event, reasonably satisfied the eligibility requirements for a Qualifying Project under the Settlement Agreement and should have been approved. Despite Mr. Lucas's rebuttal testimony that I&M has engaged in outreach and education efforts, Lucas



Rebuttal at 14-15, it appears to us that I&M's lack of written guidelines developed through stakeholder input contributed to I&M's inconsistent administration of the program.

We find that I&M unreasonably withheld its approval of Fort Wayne's application, and did not comply with the spirit and intent of the EIG provisions in the Settlement in Cause No. 44976. Therefore, we order I&M to provide Fort Wayne with the full amount of funds requested in Fort Wayne's water pressure station application (Joint Municipals' CX-8), regardless of whether the fund has been depleted as of the date of this Order. Mr. Lucas stated that I&M expects the entire \$700,000 fund allocated for economic development in Cause No. 44967 will be used before rates in this case go into effect; however, if any such funds remain as of the date of this Order, I&M shall extend the EIG program established in Cause No. 44967 until December 31, 2021, or the fund has been depleted, whichever occurs first. In addition, within thirty (30) days of the completion of the EIG program from Cause No. 44967, the Company shall make a compliance filing in this proceeding updating the Commission on any grant awards made after its rebuttal testimony was filed in this Cause.

The record shows I&M's past economic development efforts, in collaboration with its local economic development partners, may have contributed to the creation of over 4,500 jobs and nearly \$900 million of capital investment in I&M's Indiana service area over the last five years. Lucas Direct, 19. Yet, challenges remain and I&M must reasonably expand its efforts to attract and retain load. Given the remaining challenges, it is reasonable for the activities undertaken by the Company to evolve to address the needs in its service territory. I&M has identified specific areas of opportunity within its service area and proposed targeted economic development programs to address those challenges.

We find the Apprenticeship and Training and Building Development Pilot Programs are reasonably designed and intended to provide broad opportunities while remaining flexible to emerging needs. The record shows continuation of the EIG program is also reasonable and will allow I&M to continue to provide grants to eligible customers, including members of the Joint Municipal Group, Muncie, South Bend, and 39 North, to support qualifying projects. Lucas Direct, 21. These three economic development programs benefit all of I&M's customers not only through the creation of jobs and investment, but also through increased load, which spreads I&M's fixed costs over a broader base of customers, ultimately lowering customer rates.

Finally, in response to questions from Commissioner Ober during the evidentiary hearing, Mr. Lucas indicated that if the Commission were to approve these economic development programs, I&M would be willing to participate in a collaborative with all the stakeholders to reach agreeable terms on the application guidelines and to submit those terms to the Commission a compliance filing. Tr. G-51. Thus, we find that I&M shall facilitate a meeting with interested stakeholders within 12 weeks of the effective date of the Order in this Cause to collaborate on developing mutually agreeable terms on the application guidelines for the economic development programs approved above. In order that the Commission and interested stakeholders may stay abreast of the collaborative process, we direct I&M to make a progress update filing with the Commission within 90 days of the initial meeting of the collaborative. No later than December 31, 2020, I&M shall make a compliance filing with the agreed upon

guidelines. Once the EIG program guidelines are established, I&M shall make quarterly compliance filings which set forth the applications it has received, whether those requests were funded and in what amounts, or if the requests were not funded, a detailed explanation as to why.

~~The record shows I&M's economic development efforts, in collaboration with its local economic development partners, have contributed to the creation of over 4,500 jobs and nearly \$900 million of capital investment in I&M's Indiana service area over the last five years. Lucas Direct, 19. Yet, challenges remain and I&M must reasonably expand its efforts to attract and retain load. Given the remaining challenges, it is reasonable for the activities undertaken by the Company to evolve to address the needs in its service territory. I&M has identified specific areas of opportunity within its service area and proposed targeted economic development programs to address those challenges. We find the Apprenticeship and Training and Building Development Pilot Programs are reasonably designed and intended to provide broad opportunities while remaining flexible to emerging needs. The record shows continuation of the EIG program is also reasonable and will allow I&M to continue to provide grants to eligible customers, including members of the Joint Municipal Group, Muncie, South Bend, and 39 North, to support qualifying projects. Lucas Direct, 21. These three economic development programs benefit all of I&M's customers not only through the creation of jobs and investment, but also through increased load, which spreads I&M's fixed costs over a broader base of customers, ultimately lowering customer rates.~~

~~We pause briefly to address the concerns of Mr. Cearley and Mr. Fasick regarding I&M's administration of the EIG program. Mr. Lucas responded that I&M has engaged in substantial outreach and education efforts. Lucas Rebuttal, 14-15. Further, he said I&M continues to administer the EIG program in an objective and reasonable manner consistent with the terms of the Settlement Agreement approved in Cause No. 44967. *Id.*, 16. We need not address these individual complaints over whether I&M has complied with the terms of the Settlement Agreement in Cause No. 44867 as to individual grant applications. If any party believes that I&M is in breach of the Settlement Agreement, it should file a complaint to enforce the Settlement and not air such allegations during the course of a general rate case. *See U.S. Steel v. Northern Ind. Pub. Serv. Co.*, Cause No. 43204, 2007 WL 8420686 (IURC 5/9/2007) (resolving complaint regarding interpretation of prior settlement agreement). We find I&M's proposed economic development pilot programs in this case are reasonable and not excessive. We further find that these pilot costs are appropriately included in the Company's revenue requirement, and should be approved.~~

**D. Employee Medical Expenses.**

1. OUCC. Mr. Mark Garrett testified the Company's forecasted Test Year includes \$27 million for employee medical costs, which he said represents an increase of 30% over the 2018 historical level. M. Garrett, 43. He recommended an annual 5% increase be applied to medical and dental insurance expenses as well as dental costs. *Id.*, 44.

2. Rebuttal. Mr. Carlin testified the Company relied on third-party actuarial experts to evaluate and project its future medical costs. He said as a self-insured plan, AEP's medical benefit expense is actuarially determined based on the plan design, past participant medical expenses, healthcare trends (both medical and prescription) and the rates and



terms of vendor contracts that are in place. Carlin Rebuttal, 62. In addition, he noted the Company relied on third-party experts to inform the medical expense growth rates used to project 2020 medical expenses. *Id.* He discussed the factors affecting the Company's 2020 medical cost trend and concluded that the Company's use of a 5.5% medical expense escalation rate, when combined with the actuarial analysis, was a reasonable and robust method for making this projection. *Id.*, 63-64.

3. Discussion and Finding. The record shows I&M used data from its actuarial consultants, Willis Towers Watson to determine the 2019 I&M specific forecast for medical expenses. The 2020 Test Year forecast was then calculated using a 5.5% medical expense escalation rate. Carlin Rebuttal, 63. The record further shows that the 5% escalation rate used by Mr. Garrett does not reflect utility industry specific data; it also fails to take into account plan sponsor specific information, such as participant demographics. The energy and utilities rates in the same survey Mr. Garret relied on were 6.8 percent and 6.2 percent for 2018 and 2019, respectively. *Id.* Other factors affecting the Company's 2020 medical cost trend included the saturation of generic drugs that previously helped hold down prescription drug expense increases, relatively fewer patented drugs being eligible for traditional generic competition and the impact of higher priced specialty drugs, especially biologics. *Id.*, 63. Mr. Carlin explained that due to the Companies' proactive management of its medical plan design and efficiency to both contain medical cost increases and maximize its value to participants, I&M was comfortable applying a lower 5.5 percent escalation rate, rather than the higher 6.0 percent rate for the Energy and Utilities sector that this survey projected. *Id.* at 63-64. We find it is unreasonable to further decrease the escalation rate to reflect non-utility industry data as proposed by Mr. Garrett. Accordingly, we further find the Test Year forecast presented by the Company is reasonable and reject the OUCC's proposed adjustment.

#### **E. Employee Adjustment – Full Time Employee.**

1. Industrial Group. IG witness Gorman proposed to reduce I&M's projected Full Time Employee ("FTE") level of 2,305 down to 2,199 because he stated I&M has not filled all of its budgeted employee positions in the past five years. Rather, he said I&M has consistently had approximately 100 employee budgeted positions that were not filled. Mr. Gorman stated this adjustment results in a decrease in Test Year O&M expense of \$4,323,000 and a decrease of \$822,000 in capitalized costs. Gorman, 30-32; Attachment MPG-6.

2. Rebuttal. Mr. Lucas stated I&M's actual FTE headcount has been below its budgeted FTE count in recent years due to an increased amount of attrition. Lucas Rebuttal, 25. He said to the extent I&M has unfilled positions in 2020 there are potentially other components of the forecast, such as contract labor, overtime, or outside services that could potentially increase to compensate. He stated I&M has provided a comprehensive O&M forecast to accomplish the work plans presented in this case. He noted the overall forecasted O&M was reviewed by the business units and I&M management at the time the forecast was prepared and reflect what is reasonably necessary to complete the work plans in the Test Year. *Id.*

3. Discussion and Finding. The record shows I&M has prepared a comprehensive O&M forecast designed to accomplish the work plans presented in this case. Lucas Direct, 8-13; Lucas Rebuttal, 25. To the extent I&M has employee vacancies that are not

filled in 2020, or these vacancies are filled and other vacancies arise, there will not necessarily be a corresponding decrease in labor cost. This is because the forecasted work identified by I&M will still need to be completed. Lucas Rebuttal, 25. As Mr. Lucas noted, a decrease in FTE labor expense may be offset by an increase in contract labor, overtime, or other outside services to compensate. *Id.* Having found I&M's Test Year work plans to be reasonable and supported by substantial evidence, it would be unreasonable to remove the O&M and capital labor costs necessary to accomplish those work plans. Accordingly, we reject Mr. Gorman's proposed disallowance.

**F. EZ Bill Program.**

1. I&M. Mr. Williamson explained the EZ Bill Program was approved in Cause No. 45114 and is a voluntary billing option designed to allow eligible residential and small commercial customers to be charged a fixed amount per month for electric service over a 12-month period. Williamson Direct, 63. He said I&M is proposing that both EZ Bill Program costs and revenues be accounted for above the line as the program is a customer rate offering like any other I&M rate offering.

2. OUCC. Mr. Lantrip recommended the Commission require I&M to treat all EZ Bill Program profits and losses below-the-line. He said treating all such costs above-the-line would socialize costs among all ratepayers, even though not all ratepayers will qualify for or utilize this optional program. Lantrip, 2, 9-12. He suggested in lieu of rendering a decision in this case on whether EZ Bill Program costs should be treated above or below the line, it would be appropriate to see the EZ Bill Program through to the end of the three-year period, review I&M's data to verify program costs and profitability, as well as customer data and participation, in order to determine whether recovery above-the-line is appropriate in I&M's next rate case. *Id.* at 13.

3. Rebuttal. Mr. Williamson testified it is not reasonable to account for program costs and revenues below-the-line. He said the EZ Bill program is one of several customer programs that I&M provides to its customers, and the costs of offering these programs are part of I&M's overall cost of serving its customers. Williamson Rebuttal, 51. He stated since the program will be offered to a large number of customers, it is reasonable that the program costs be viewed as a cost of providing service for all customers and not just those who participate. *Id.* at 54. He said the status of the program is not cause for disallowance of these program costs and the OUCC's "wait-and-see" approach indicates the OUCC's recommendation is outcome based, not principle based. *Id.* at 55.

4. Discussion and Finding. We first note I&M is not proposing to include any costs or revenues associated with the EZ Bill Program in its revenue requirement in this Cause. Rather, I&M is requesting regulatory accounting treatment to treat the program costs and revenues as a component of I&M's cost of service in subsequent rate proceedings. Williamson Direct, 66. The OUCC asserts that the EZ Bill Program design warrants different accounting treatment from other customer rate offerings but fails to show why this is the case. As Mr. Williamson testified, the EZ Bill Program is not intended as a separate line of business or product for I&M but rather as a customer-friendly option for paying for the same electric service I&M provides all its customers. *Id.*, 64. Moreover, the record shows I&M expects 87% of

residential customers to be eligible for the program, based on their usage modeling. Williamson Rebuttal, 52. We agree with I&M that the EZ Bill Program is similar to other tariff offerings from I&M and should receive the same regulatory accounting treatment.

The evidence shows that the EZ Bill program is a utility service I&M provides its customers and therefore the associated costs and revenues are properly included in base rates as part of I&M's cost of service. In addition, over the long run, EZ Bill Program profits are expected to exceed losses, and overall EZ Bill Program revenue are expected to exceed what I&M's revenue would be under the otherwise applicable standard rates. Williamson Direct, 65; Pet. Ex. 43 (Response to IURC Docket Entry), 24. In other words, accounting for EZ Bill Program revenue above the line is expected to benefit I&M's customers by offsetting I&M's cost of service and mitigating potential future rate increases. In approving the EZ Bill Program, the Commission found that approval of the EZ Bill Program "will provide benefits to customers in several ways." *Re Indiana Michigan Power Co.*, Cause No. 45114, p. 15 (IURC 12/27/2018). Accordingly, we find it appropriate to include the EZ Bill Program costs and revenues in I&M's cost of service for purposes of rate setting.

#### **G. Factoring Expense.**

1. OUCC. Mr. Mark Garrett stated that I&M's forecasted factoring expense should be reduced to reflect the most recent three-year average. He said all indications are that interest rates will be lower in the rate effective period and thus the Company's requested level of factoring expense is overstated. Garrett, 54-55.

2. Rebuttal. Mr. Lucas explained the Test Year factoring expense forecast is based on reasonable assumptions at the point in time the forecast was prepared. Lucas Rebuttal, 23. He said these assumptions take into consideration the best information available at the time and provide a more accurate methodology to develop a forward-looking projection than simply using a 3-year average of historical data as Mr. Garrett proposes. He stated contrary to Mr. Garrett's assumptions, recent trends in I&M's factoring expense show the amount included in the Test Year may be understated and explained this corroborates that the Test Year level is reasonable and no adjustment should be made. *Id.*, 24-25.

3. Discussion and Finding. I&M's factoring expense includes four primary components: Bad Debt Expense, Agency Fees, Carrying Cost, and Bank Fee Expense. Lucas Rebuttal, 23. The OUCC identified a recent decline in one component but did not take into account any other trends that would also impact factoring expense. For example, the amount of bad debt expense from January through July of 2019 increased by 23% as compared to the same period in 2018. *Id.*, 24. The record also shows that I&M's factoring expense for the period from August 2018 through July 2019 was \$10.6 million (total Company) which exceeds the \$9.7 million reflected in the Test Year. *Id.* Accordingly, we find the Company's Test Year forecasted level of factoring expense to be reasonable.

#### **H. I&M IM Plugged In Pilot Program.**

1. I&M. Mr. Lehman discussed the Company's proposed three-year pilot program to encourage plug-in electric vehicle ("PEV") adoption in a way that optimizes the

overall electric system. The program consists of a number of tariffs and incentives targeting residential and small commercial PEV charging; multi-unit dwelling charging; commercial and industrial fleet and workplace charging; and electric vehicle education and technical development. He supported the *IM Plugged In* program costs, which total \$700,000 per year. Lehman Direct, 3. He described the need for the pilot and identified the benefits to participants and all other I&M customers. *Id.*, 4-20.

Mr. Williamson stated because the level at which customers will participate in the *IM Plugged In* program is difficult to predict, I&M has not included any transportation electrification costs in its Test Year cost of service. Williamson Direct, 59. Instead, he said I&M requests deferral accounting authority to defer the actual cost of transportation electrification incentives as a regulatory asset to be recovered in I&M's next base rate case. *Id.* He explained the requested accounting treatment and said that to recognize the time value of money/opportunity cost incurred by the Company, I&M will accrue carrying costs on the deferred unrecovered balance using the pre-tax WACC rate approved by the Commission in this proceeding. *Id.*

2. OUCC. Ms. Aguilar opposed inclusion of the *IM Plugged In* program costs, stating I&M did not provide empirical evidence that access to 240V charging equipment is an actual barrier to EV adoption or that a rebate will overcome the barrier. Aguilar, 17-19.

3. South Bend. South Bend witness Dorau agreed the *IM Plugged In* program is sensible and helps overcome barriers to PEV adoption while avoiding potential negative impacts to the shared grid. Dorau Direct, 16.

4. Rebuttal. Mr. Lehman clarified that I&M is not proposing the incentive because 240V charging is a barrier to electric vehicle adoption. *Id.* He explained that many PEV owners can support their daily driving through 120V charging; however, 240V charging is necessary for customers to have the ability to easily shift their entire charging load to off-peak times. Lehman Rebuttal, 5. He said the number of hours necessary to charge a PEV is significantly reduced when using 240V charging as opposed to 120V charging and this is why I&M is proposing to provide an incentive for customers to install 240V charging equipment – so that they can take advantage of the proposed off-peak charging rate and shift all of their PEV charging to off-peak times. *Id.* Mr. Lehman explained that I&M used reasonable projections and data for its estimate that each residential and small commercial participant can be expected, on average, to provide \$579 in net benefits to all I&M customers over a 10-year period. Lehman Rebuttal, 2. He said one reason the Company has proposed to implement the PEV program as a pilot is to obtain empirical data, evidence and customer feedback necessary for developing future programs that focus on increased system utilization and downward pressure on customer electric rates. *Id.* He added that the customer benefits from the residential and small commercial component of I&M's proposed *IM Plugged In* pilot program can be reasonably estimated before the program is implemented and I&M-specific data is available to support these estimated benefits. *Id.*

5. Discussion and Finding. The record shows PEV adoption is accelerating and that it is important that load from electric transportation be integrated into the

grid in a manner that minimizes or eliminates additional system costs. Lehman Direct, 4-7. I&M's pilot is relatively modest in size, and is reasonably focused on the highest value applications for customers and grid optimization - locations where PEVs are parked on a regular basis for significant durations and perform the greatest percentage of their charging. Lehman Rebuttal, 11. The *IM Plugged IN* pilot will also gather additional empirical evidence to inform future program offerings. While Ms. Aguilar asserted I&M lacked empirical data to support the pilot, we note the Company used Indiana-specific census information, data from PEV charging studies, and other reasonable assumptions to estimate the benefit of the program to non-participants. Lehman Rebuttal, 2-4. That estimate shows that each residential and small commercial participant is expected, on average, to provide net benefits of \$579 to all other I&M customers over a 10-year period. Lehman Direct, 17. Mr. Lehman indicated I&M would be amenable to adjusting the terms of the program to allow existing PEV owners who have not installed 240V charging equipment at their parking location to be eligible to receive the incentive under the program. Lehman Rebuttal, 8. We find this modification to be reasonable and consistent with the intent of the program. Accordingly, the Commission finds that the *IM Plugged IN* pilot program is reasonable and we reject the OUCC's proposed disallowance of the *IM Plugged IN* program costs. We further approve I&M's request for deferral accounting authority related to the *IM Plugged In* program, including carrying costs on the unrecovered balance using the pre-tax WACC.

## **I. Incentive Compensation.**

1. OUCC. Mark E. Garrett, the president of Garrett Group Consulting, Inc., testified with respect to incentive pay. I&M had included its incentive plans in its MSFR submission. Mr. Garrett provided a brief description of I&M's incentive plans and noted that there is a financial performance funding trigger. M. Garrett, 7. He noted there were other measures that included financial performance, and he cited specifically to transmission investment. *Id.* p. 12. He also cited to *Indiana American Water Company*, Cause No. 44022, wherein the Commission reduced recovery of that utility's incentive pay to 15% of target.

Mr. Garrett testified that annual incentive pay ("AIP") is not "reasonably necessary to attract" a talented workforce. *Id.*, 17. He then cited to a number of orders in Oklahoma, Texas, and other western states addressing incentive compensation recovery. *Id.*, pages 17-23. He contends the question is not what the company should pay to attract and retain qualified personnel, but who should pay for it. *Id.*, 26. Ultimately, he recommended a 50/50 sharing between customers and shareholders. *Id.*, 29. He applied his adjustment to the capitalized portion of labor as well. *Id.*, 30.

Mr. Garrett also proposed to disallow in its entirety Petitioner's long-term incentive plan ("LTIP"), which he described as being "for executives and managers." *Id.*, 30-32. He cited to the disallowance of LTIP in *Indiana American's* rate case in Cause No. 44022. He further cited to orders from other states. *Id.* pp. 32-36.

2. Industrial Group. Mr. Gorman testified on behalf of the Industrial Group, and he argued that the portions of Petitioner's incentive plan tied to financial performance should be disallowed. He proposed removing that portion of Petitioner's short-term



incentive plan. He also proposed to disallow the entirety of Petitioner's LTIP because, in Mr. Gorman's opinion, LTIP is purely financial. Gorman, 24-29.

3. Rebuttal. Petitioner's witness Carlin testified in rebuttal to the proposed incentive pay disallowances. He testified Mr. Garrett is disregarding 20 years of IURC precedent concerning the recovery of incentive pay. Carlin Rebuttal, 2. He noted the recovery of incentive pay dates back to *Public Service Indiana*, Cause No. 40003 (IURC 9/27/1996). He testified the presence of a financial metric trigger has previously been rejected by this Commission as a reason to disallow recovery of incentive pay and cited to *Indiana American Water Company*, Cause No. 42029, (IURC 11/6/2002), where Indiana American had an earnings per share "gatekeeper". *Id.*, 8. Mr. Carlin provided the various factors that go into the calculation of incentive pay and noted both Mr. Garrett and Mr. Gorman overstated the portion made up by financial performance. In fact, it is only 40% of the total AIP award that is related to financial performance. *Id.*, 10. The primary measures are non-financial operating measures. *Id.* He disputed Mr. Garrett's testimony that operational portions are also tied to financial metrics. He explained the transmission construction measurement is tied to completing approved projects expeditiously and under budget and not to the selection of projects to complete. *Id.*, 24.

Mr. Carlin corrected Mr. Garrett's quote of the Indiana standard. While Mr. Garrett had stated it is whether incentive compensation is reasonably necessary to attract a talented workforce, the actual standard is that incentive pay does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce. *Id.*, 11. Mr. Carlin noted the significance of the distinction is that Indiana does not look at incentive pay in isolation but rather looks at total compensation and asks whether total compensation is greater than that reasonably needed to attract a talented workforce. *Id.*, 12. He cited to *Indiana American Water Company*, Cause No. 43680 (IURC 4/30/2010) for this proposition. He then presented an analysis showing how I&M's average target total compensation is within a single digit percentage point of the market median for each type of employee but would fall well below the median if the incentive compensation were not provided. *Id.*, 13-14.

Mr. Carlin also responded to Mr. Garrett's citation to the 15% allocation to shareholders with respect to Indiana American. He noted that in this case, the incentive compensation proposed is based upon the target award, and everything above target is allocated to shareholders. He presented an analysis that showed over the past five years the historic payment has been greater than 150% of target and in some years as high as 191% of target. *Id.*, 18-19. With respect to the earnings per share trigger, he explained it is set at a low level that is readily achievable and is only intended to protect against particularly difficult financial circumstances. *Id.*, 22. He then responded to Mr. Garrett's surveys of other states. *Id.*, 25-30.

With respect to Petitioner's LTIP, Mr. Carlin explained LTIP is available to 1,150 employees. Seventy-five percent of the LTIP award is based upon financial performance, but 25% consists of restricted stock units. He said the restricted stock units are provided as a retention goal and that the restricted stock units do not have any metrics, goals, or measures. *Id.*, 48-49, 51.

4. Discussion and Finding. "The Commission has long recognized the value of incentive compensation plans as part of an overall compensation package to attract and

retain qualified personnel.” *Northern Ind. Pub. Serv. Co.*, Cause No. 43526, p. 63, 2010 WL 3444546, 284 P.U.R.4th 369 (IURC 8/25/2010); *see Indiana-American Water Co.*, Cause No. 44022, p. 66, 2012 WL 2154248 (IURC 6/6/2012); *Southern Ind. Gas & Elec. Co.*, Cause No. 43839, p. 50, 2011 WL 1690057, 289 P.U.R.4th 9 (IURC 4/27/2011); *Indiana-American Water Co.*, Cause No. 43680, p. 74, 2012 WL 2154248 (IURC 4/30/2010); *PSI Energy, Inc.*, Cause No. 42359, p. 89, 2004 WL 1493966, 234 P.U.R.4th 1 (IURC 5/18/2004); *Indiana-American Water Co.*, Cause No. 42029, p. 45, 2002 WL 32091039 (IURC 11/6/2002), and *PSI Energy, Inc.*, Cause No. 40003, p. 56, 1996 WL 767535, 173 P.U.R.4th 393 (IURC 9/27/1996). In addition to this long line of precedent, there are numerous other orders where we have authorized recovery of incentive pay through settlement agreements or where the recovery was not opposed by any parties. *See Indiana-American Water Co.*, Cause No. 45142, 2019 WL 2903633 (IURC 6/26/2019); *Northern Ind. Pub. Serv. Co.*, Cause No. 44688, 2016 WL 3996436 (IURC 7/18/2016); *Indianapolis Power & Light Co.*, Cause Nos. 44576 & 44602, 2016 WL 1118795 (IURC 3/10/2016); *Southern Ind. Gas & Elec. Co.*, Cause No. 43112, 2007 WL 8420645 (IURC 8/1/2007). While Mr. Garrett has provided a lengthy discussion of decisions from regulatory commissions in other states, we find it provides little to no discernable value to the question before us. Further his exhortation that the question is not whether I&M *should* pay incentive pay but rather who should fund it is nothing more than a plea for us to abandon our long-held standard.

The recovery of incentive compensation through rates dates at least back to *PSI*, Cause No. 40003, but the first pronouncement of our standard for recovery can be found in *Indiana American*, Cause No. 42029. There, the Commission reviewed *PSI* and distinguished it from the order in *Indiana Natural Gas*, Cause No. 40382, 1996 WL 34604585, issued one week earlier. In the *Indiana Natural Gas* decision, the Commission had addressed recovery of a profit sharing plan. In distinguishing the two cases, the Commission stated:

Two things can be taken from these orders: (1) a pure profit-sharing plan which only incents employees to become more profitable may be more appropriate for funding solely by the shareholder than a plan which also ties compensation level to better service to the customer; and (2) a plan which causes compensation to exceed levels which are reasonably necessary for the utility to attract its workforce should be disallowed as an unnecessary expense.

*Indiana American*, Cause No. 42029, 45.

Indiana American’s plan consisted of three components: gatekeepers, performance goals, and individual multipliers: “First, the AIP contains a gatekeeping component that ensures that AIP payments are made only when two targets are met: a minimum earnings per share (“EPS”) of Indiana American and the attainment of individual performance expectations of the participating company and the employee.” *Id.*, 43. If the gatekeepers were met, the plan consisted of two performance goals: financial performance goals and operational goals. *Id.* We allowed full recovery applying the new test we had announced.

In the next *PSI* rate order, Cause No. 42359, we confirmed the third component of the test: “Shareholders are allocated part of the cost of the incentive compensation programs.” *Id.*,



89. This three-part test has been consistently applied ever since. We will, therefore, apply it for purposes of evaluating the objections to I&M's recovery.

I&M's plan incorporates operational as well as financial performance goals and is not a pure profit sharing plan. Mr. Garrett's objection to the presence of a financial "trigger" fails because there was a financial trigger or "gatekeeper" tied to parent company earnings per share in the very first order authorizing recovery of Indiana American's incentive compensation in Cause No. 42029. As to the suggestion of both Mr. Garrett and Mr. Gorman that we should exclude from recovery the portion of incentive compensation that is related to financial metrics, this has never been the standard and it is an argument we have specifically rejected previously. *NIPSCO*, Cause No. 43526, 63 and *SIGECO*, Cause No. 43839, 50. The fact that there are financial metrics in the incentive compensation plan does not make it a pure profit sharing plan, and we have historically refused efforts such as those proposed here to exclude recovery of those portions of the plan that are tied to financial metrics.

The next element is whether the plan "causes compensation to exceed levels which are reasonably necessary for the utility to attract its workforce." We agree that Mr. Garrett has misquoted our standard. The question is not whether incentive compensation, by itself and in isolation, is necessary to attract the workforce; the question is whether the entire compensation package (including the incentive compensation plan) produces compensation levels that are excessive. This should have been apparent from our orders in *NIPSCO*, Cause No. 43526, *Indiana American*, Cause No. 43680, and *SIGECO*, Cause No. 43839. No one here contends that I&M's total compensation levels are excessive and Mr. Carlin's presentation of the salary bands in comparison to the medians confirms that total compensation is not excessive. Carlin rebuttal, 13-15.

The final issue is the portion of incentive compensation to be assigned to shareholders. I&M's evidence is that it has only included the target level of incentive compensation in its revenue requirement, and all incentive compensation in excess of target is effectively allocated to shareholders. Carlin Rebuttal, 17. A five-year history of incentive compensation payouts was provided, which showed the five-year average payout was more than 150% of target and had been as high as 191% of target. Carlin Rebuttal, 18 (Revised). These facts align with the facts in *SIGECO* and are readily distinguishable from the facts presented in *Indiana American*, Cause No. 44022. There, Indiana American's historic payout averaged 100.33% of the target proposed to be included in rates such that only 0.33% of the historic average was being allocated to shareholders. In this Indiana-American case, the Commission distinguished those facts from *SIGECO* and noted: "However, in that case [*SIGECO*] the evidence demonstrated that the Petitioner's average payout had exceeded target by as much as 190% over the past ten years and the shareholders absorbed the cost of incentive compensation that exceeded the target level." also Indiana-American (IURC 6/6/2012), Cause No. 44022, 66; Carlin Rebuttal, 19. In the instant case, the portion of incentive compensation that is allocated to shareholders is all payments in excess of target, which we find to be appropriate.

The final issue raised is with respect to recovery of LTIP. This was described by Mr. Garrett as incentive compensation for executives, but that is not an accurate description. More than 1,100 employees received LTIP. Moreover, while the portion of LTIP that is tied to financial metrics is greater than the portion tied to short-term incentive compensation, neither

Mr. Garrett nor Mr. Gorman make any mention of the remaining portion, the restricted stock units that are intended to encourage retention. The LTIP that we rejected in Cause No. 44022 was reserved for high-level management positions at Indiana American. That is not the case here, and so we find it to be recoverable as we did in *SIGECO* and *PSI*. Accordingly, we find that Mr. Garrett's proposed adjustments to short-term and long-term incentive pay should be rejected.

## **J. Pension Expense**

1. OUCC. OUCC witness Mark Garrett testified I&M did not include the return on pension benefit plan assets in its calculation of pension expense for ratemaking purposes. He said that, as a result, Petitioner had included test year employee benefits expense of \$39.5 million. M. Garrett, 41-42. He based this on his review of MSFR 1-5-8(a)(13). Mr. Garrett ultimately proposed to reduce Petitioner's Test Year pension expense on a jurisdictional basis by \$15,496,003.

2. Rebuttal. Mr. Ross testified Petitioner's contributions to the pension fund in excess of pension expense lower pension expense and result in lower customer rates. Ross Rebuttal, 11. He was asked on redirect about a cross-examination exhibit and testified that the return on the pension fund is included as an offset to the revenue requirement in the cost of service. He testified on redirect that the confusion is likely due to a recent change in generally accepted accounting principles ("GAAP") which modifies how pension expense is reported for financial reporting purposes. Tr., I-65-66.

3. Discussion and Finding. The OUCC's confusion in this case over pension expense apparently results from a recent Financial Accounting Standards update, which changes how pension expense is reported for GAAP purposes. FASB Update No. 2017-07 requires that the service cost component of pension expense is to be reported in the same line item or items as other compensation costs. All other components of pension expense (*i.e.*, "non-service costs," which would include return on pension plan assets) are reported separately from the service cost and outside a subtotal of income from operations. Pet. Cross Ex. 3, 2; Tr. K-21-23. We see this change reflected in Petitioner's income statement Exhibit A-4, where employee benefits (\$25,796,466) and pension plan (\$13,721,467) are shown as a component of Operation and Maintenance expense on page 8 and the non-service cost components (including return on plan assets) is reported as non-operating income (\$20,226,564) on page 10. The MSFR upon which Mr. Garrett relied for purposes of his proposed adjustment requests only the pension expense included in Operation and Maintenance, and it sets forth the service cost component as the amount to be charged to Operation and Maintenance expense, consistent with the new accounting standard. Pet. Cross Ex. 2. Nothing in this MSFR requests the amount of pension expense included in the revenue requirement.

The OUCC asked in discovery about this MSFR and I&M responded, in part, "The non-service benefits amount of (\$20,226,564) represents a reduction to O&M for the non-service components primarily of pension, supplemental pension and OPEB." Pet. Cross Ex. 4. The attachment provided with this response shows \$20,226,564 of non-operating income reported as non-service costs was a reduction to the \$25,796,466 in employee benefits and \$13,721,467 in pension benefits representing the service cost component, producing a net total of \$19,291,369. We received into evidence the workpapers showing the calculation of Petitioner's revenue

requirement as Pet. Cross Ex. 5. This is the Excel version of Petitioner's Net Operating Income Statement Adjusted for Ratemaking Purposes. This exhibit confirms that net employee pension and benefits included in the revenue requirement total \$19,291,369, which is the amount of total employee benefits and pension expense net of the non-service component of pension costs. *Id.*, Tab – "Adjustments", Cell F-152.

There is no dispute, and we find that customer rates in Indiana should reflect the non-service cost components of pension expense despite the new financial accounting standard update requiring them to be reported outside of operating income. Petitioner's proposed revenue requirement does include the non-service cost component, so we find Mr. Garrett's proposed adjustment should be rejected.

#### **K. Major Storm Expense and Major Storm Reserve.**

1. I&M. Mr. Williamson testified I&M requests to continue the Major Storm Damage Restoration Reserve as approved in Cause No. 44075 and 44967. Williamson Direct, 6, 58. Messrs. Williamson and Isaacson explained I&M's Indiana jurisdictional, major storm distribution O&M expense has ranged from as high as \$12.5 million to as low as \$1.2 million from 2008 to 2018, compared to the baseline of \$4,047,529 approved in Cause No. 44967. Williamson Direct, 58; Isaacson Direct, 39-40. I&M proposed to continue the Major Storm Reserve and associated accounting using the current \$4,047,529 baseline given the unpredictable and potentially significant nature of these costs. Williamson Direct, 58-59; Isaacson Direct, 41.

2. OUCG. The OUCG did not oppose I&M continuing the Major Storm Reserve but recommended decreasing the Major Storm Reserve baseline to \$2,473,000 based on the five-year average major storm expenses for the period 2014-2018. Alvarez, 18-19, 38.

3. Rebuttal. Mr. Williamson said I&M was agreeable to the OUCG's proposal with one modification. He said if historical dollars are used to determine a future cost, inflation must be considered. Williamson Rebuttal, 63. He applied the Gross Domestic Product as a general measure of inflation and determined that the Commission should use \$2,675,000 as the distribution major storm reserve baseline. *Id.*, 63-64.

4. Discussion and Finding. The record shows I&M's distribution O&M expenses associated with major storm restoration efforts can be significant, are volatile in nature, and are largely outside the Company's control. Williamson Direct, 58; Isaacson Direct, 39-41. No party opposed the continuation of the Major Storm Reserve and we find it to be a reasonable approach to addressing these significant, variable costs. While we find, based on the evidence presented, the five-year historical average is a reasonable starting place for setting the Major Storm Reserve baseline, we agree with I&M that it is appropriate to adjust those historical costs for inflation to 2020 dollars in determining the baseline going forward. Accordingly, we approve the continuation of the Major Storm Expense Reserve and find the appropriate baseline to use is \$2,675,000. We grant I&M all necessary accounting authority to follow past practices of deferring the actual amount above and below this level.

**L. Nuclear Decommissioning Funding Expense.**

1. I&M. Mr. Hill testified the annual decommissioning funding amount should be increased to \$10 million from the current level of \$2 million. Hill Direct, 2. He discussed the estimation of future decommissioning costs presented by Mr. Knight, the rules and guidelines for determining adequate funding levels, and his Monte Carlo methodology for determining an appropriate funding level. *Id.*, 3-23. He explained his modeling shows that at an annual funding level of \$10 million the probability of having sufficient funds is approximately 90%. Hill Direct, 23. He emphasized that it is important to increase the funding level now, when there is time to gradually protect against a future shortfall, rather than suffer one prior to decommissioning, with little time to recover. He said I&M will continue to report to the Commission every three years on the adequacy of the existing provision, however, and I&M may recommend adjusting the level of decommissioning fund contributions needed in the future. *Id.*, 24-25.

Mr. Hill stated the Spent Nuclear Fuel trust is adequately funded at the present time and said no additional funding is necessary at this time. Hill Direct, 30. He also discussed the investment guidelines for the Spent Nuclear Fuel trust and recommended for the balance of Indiana jurisdictional pre-April 7, 1983 assets that exceed the Indiana jurisdictional liability by a factor of 1.05 or more, those assets should be permitted to be invested pursuant to the investment guidelines currently in place for the Indiana Nuclear Decommissioning Trust. *Id.*, 31-32. He said providing the option to invest the surplus in this manner can provide improved diversification benefits compared to investing under the current guidelines and provides flexibility. *Id.*, 32-36.

2. OUCC. Mr. Eckert recommended the current annual contribution be reduced to zero, asserting that the fund is already overfunded. Eckert, 9. He said I&M's compliance with NRC minimum funding requirements and his review of the market value of the decommissioning trust fund supported his conclusion that there will be sufficient funds available to support a discontinuation of funding in this case. *Id.*, 9-13.

3. Intervenors. IG witness Gorman and Joint Municipal Group witness Cannady both recommended annual funding remain at \$2 million. Gorman, 23; Cannady, 4. Mr. Gorman stated the forecasted value of trust fund assets, assuming more reasonable modeling assumptions, is adequate and argued there are additional factors that act as contingencies to provide assurance that the trust fund will be capable of paying the decommissioning costs. Gorman, 15-24. Ms. Cannady noted the current balance meets NRC requirements, the Monte Carlo simulation results from I&M show that scenarios using the \$2 million per year provide over 84% probability that the fund will be fully funded by the time decommissioning begins, and questioned the reasonableness of the increased ~~labor~~-cost components reflected in the decommissioning cost estimate. Cannady, 21-26. She also noted the possibility that the Cook operating licenses could be extended in the future. *Id.*, 28-29.

4. Rebuttal. Mr. Hill stated Mr. Eckert's estimated decommissioning cost incorrectly excludes on-going spent fuel storage costs and explained Mr. Eckert's reference to the NRC minimum value excludes removal and disposal of spent fuel and the removal of clean structures. Hill Rebuttal, 2-3. He disagreed with Mr. Eckert and Ms. Cannady that compliance with NRC minimum funding guarantees I&M will have sufficient funds at the end of Cook

Plant's life to successfully decommission the plant. *Id.*, 3-4. Mr. Hill also responded to Mr. Gorman's arguments against increasing nuclear decommissioning contributions and defended the reasonableness of his Monte Carlo modeling. Hill Rebuttal, 8-13.

5. Discussion and Finding. The purpose of funding the nuclear decommissioning trust is to ensure that adequate funds are available to pay for the safe dismantlement of the Cook Plant and related facilities, disposal of the radioactive portions of the plant, storage of spent nuclear fuel as needed, restoration of the plant site, and to comply with certain State and NRC requirements. Hill Direct, 3. The nuclear decommissioning expense is included in the revenue requirement to allocate the cost of decommissioning the plant to the customers who are receiving the benefits of its generation during its useful life. If at the time of retirement, there are adequate funds in the decommissioning fund, then the regulatory objective has been accomplished and generational inequity avoided; if funds are inadequate, then tomorrow's customers will pay higher rates to recover costs that should be recovered today. The funds collected must be placed into a trust account which neither I&M nor AEP can access for any purpose other than decommissioning the Cook Plant. Once the decommissioning is complete, any remaining funds will be returned to customers.

The parties disagree over the annual funding level of the Trust. The record shows compliance with the NRC minimum funding requirement referenced by the OUCC and Joint Municipal Group does not mean the decommissioning trust is sufficiently funded; indeed, the NRC specifically states that its requirements "are not intended to be used by themselves or by other agencies to establish rates." Hill Rebuttal, 4; 10 CFR § 50.75. We have determined that the level of funding required from ratepayers for a nuclear decommissioning trust must be fair and reasonably provide sufficient funding for the dismantling efforts at the Cook Plant. In this proceeding, Petitioner proposes to quadruple its existing funding levels. agree with I&M that a The Monte Carlo simulation can be a reputable methodology for does a much better job calculating real-world risk and return trade-offs to capture investment and liability growth risks than the alternative calculations presented by the OUCC, IG and Joint Municipal Group. However, it is not reasonable to expect that the funding level should almost totally eliminate even highly speculative risks. The Company has requested a \$10 million annual funding that provides for a measure of 90% funding assurance using the Monte Carlo simulation. The Joint Municipal Group used the exact same simulation, and found that a measure of 84.9% funding assurance can be met with a \$2 million per year annual funding requirement.

We must also consider the possibility that the Company will take advantage of the opportunity to extend the existing nuclear operating license for an additional 20 years. Mr. Hill explained that the Monte Carlo simulation provides a range of possible outcomes and considers many different aggregating and mitigating factors. While the issue of license renewal is not directly before us, we believe that possibility of license renewal should be taken into consideration as a mitigating factor to the Company's risk scenarios because such an extension would significantly impact the need for funding. In particular, we note both Mr. Eckert and Ms. Cannady assume riskless investment return and ignore necessary decommissioning costs that are not captured in the NRC minimum requirement. Hill Rebuttal, 5. As Mr. Hill explained in rebuttal, Mr. Gorman did use I&M's Monte Carlo model, but manipulated the assumptions in ways that are all favorable to his arguments. *Id.*, 8. The record shows Mr. Gorman's assumptions are internally inconsistent and that seemingly subtle changes, such as using the historical rate of

~~inflation at 2.9% shown in Mr. Gorman's Table 3 instead of the 2.25% used by Mr. Gorman in the model, can cause the probability of successful decommissioning to plunge to 61% for the current funding level of \$2 million and to 73% for a contribution level of \$10 million. Hill Rebuttal, 10-11. Given the importance of ensuring a stable, adequately funded decommissioning trust fund, we find the OUCC, IG and Joint Municipal Group proposals to be unacceptable. This is particularly the case here, where the record shows I&M is only five years away from the point that it plans on de-risking the trust asset investment profile, meaning the window of opportunity to make up for any current funding deficit is getting smaller and smaller. Hill Rebuttal, 13.~~ Accordingly, we find I&M's ~~proposed~~existing annual contribution level of ~~\$240~~ million is reasonable and is approved.

I&M requested that certain language be included in the Commission's Order to assist I&M in obtaining compliance with regulations of the Internal Revenue Service regarding qualified nuclear decommissioning trust funds. Hill Direct, 25. The language requested by I&M updates language incorporated into previous Commission rate orders. ~~No party objected to this request. Accordingly~~Consistent with our finding to continue the existing funding level, we incorporate the following disclosures into this Order:

- (1) The amount of decommissioning costs to be included in the cost of service for Units No. 1 and No. 2 of the Donald C. Cook Plant is ~~\$51.00~~ million and ~~\$51.00~~ million, respectively.
- (2) The assumptions used in determining the amount of the decommissioning costs to be included in the cost of service for each of the two Units are as follows:
  - (a) The after-tax rate of return assumed to be earned by amounts collected for decommissioning is 5.0%.
  - (b) The proposed method of decommissioning each of the two Units assumed in the Decommissioning Study of the D.C. Cook Nuclear Power prepared by TLG dated January 4, 2019 (the "TLG Study") is immediate decommissioning of the site ("DECON"), on-site storage of spent fuel, and clean removal.
  - (c) The total estimated cost of decommissioning in 2018 dollars in total for the Donald C. Cook Plant is \$2,404,017,000, consisting of \$2,032,121,000 in base decommissioning costs per the TLG Study, \$335,013,000 of annual post decommissioning spent fuel storage costs through 2098, and \$36,883,000 for the eventual decommissioning of the independent spent fuel storage installation. The estimated cost of decommissioning for each unit is \$1,165,328,721 for Unit 1 and \$1,238,688,279 for Unit 2.
  - (d) The methodology used to convert the current dollars estimated decommissioning cost to future dollars estimated decommissioning costs is to use the formula prescribed by the Nuclear Regulatory Commission ("NRC") for development of escalation rates for nuclear decommissioning costs. The NRC formula breaks the decommissioning costs into (3) three components: labor, energy, and radioactive waste burial. The weight of each component is based on the detailed estimates in the TLG Study. A base rate of 2.25% was assumed. The escalation rates for labor, energy and radioactive waste burial were



assumed to exceed the base rate of inflation by 0.53%, 1.61% and 0.38%, respectively.

(e) Decommissioning costs to be included in the cost of service are an amount of \$192.0 million apportioned between units as shown in Item No. 1 expected to be included annually in the cost of service for each of the two units, continuing through the dates shown in Item (f), unless changed by future order of the Commission.

(f) The estimated date on which it is projected that the nuclear unit will no longer be included in I&M's rate base is October 31, 2034, for Unit 1 and December 31, 2037, for Unit 2.

(g) The TLG Study was utilized in determining the amount of decommissioning costs to be included in I&M's cost of service.

Finally, I&M proposed certain changes in the Spent Nuclear Fuel trust investment guidelines. No party challenged these changes and we find them to be reasonable. The record shows the current investment guidelines were established in the 1980s and that circumstances warrant change. Hill Direct, 32. I&M presented a Monte Carlo simulation to evaluate potential asset allocation policies and showed that the proposed investment guidelines would potentially extend the surplus life and provide benefits through diversification. Hill Direct, 35-36. Accordingly, we approve I&M's requested change to the investment guidelines for the pre-April 7, 1983 Spent Nuclear Fuel trust.

#### **M. Rate Case and Nuclear Decommissioning Study Expense.**

1. I&M. Mr. Williamson supported the adjustment for rate case expense and incremental nuclear decommissioning study expense. He proposed total estimated expense of \$1.55 million, which he proposed to amortize over two years. Williamson Direct, 30.

2. OUCC. Mr. Mark Garrett proposed two changes to Petitioner's adjustment. First, Mr. Garrett proposed to amortize rate case expense over three years rather than two. Second, he proposed to limit the recovery of outside counsel fees to \$500,000. He viewed the legal fees in the instant case to be high as a percentage of overall rate case expense. M. Garrett, 51. He based his recommendation on outside counsel fees estimated on selected rate cases he presented from other states. In those cases, the utility had relied on in-house legal counsel for most of the work and, in Mr. Garrett's opinion, to do so would be more cost effective based on the Bureau of Labor Statistics mean salary levels for lawyers. M. Garrett, 52-53.

3. Rebuttal. Mr. Williamson objected to using rate case expense figures in other jurisdictions because the regulatory requirements will vary from state to state. As an example, he cited rate case expense in a Texas case involving an AEP affiliate, where outside counsel expense was estimated at more than double the amount here. Williamson Rebuttal, 32-33. Mr. Williamson also compared the proposed rate case expense here to rate case expense in other recent Indiana cases. Here, total rate case expense is estimated at \$1.55 million. The total rate case expense estimated in the other recent Indiana cases is *Duke Energy Indiana, LLC* (Cause No. 45253) - \$2,853,000; *Northern Ind. Pub. Serv. Co., LLC* (Cause No. 45159) - \$2,076,000; *Indianapolis Power & Light Co.* (Cause No. 45029) - \$3,980,000; *Indiana American*



*Water Co.* (Cause No. 45142) - \$2,177,462; *Northern Ind. Pub. Serv. Co., LLC* (Cause No. 44988) - \$1,300,000; *I&M* (Cause No. 44967, the last case) - \$1,470,000. Williamson Rebuttal, 33-35. He testified the total rate case expense estimated here was lower than the other two major electric cases that were pending in 2019 and was, indeed, the lowest of all of these other cases excluding the *NIPSCO Gas* rate case (involving far fewer intervenors) and I&M's last rate case (filed two years earlier). *Id.*, 35.

4. Discussion and Finding. Mr. Garrett did not question the amount of work that is required for a rate case in Indiana, nor did he dispute the reasonableness of the fee that outside counsel is charging for the work they are being asked to do. Instead, his argument was based upon the percentage of overall rate case expense attributable to legal fees and speculation that it would be more cost effective to rely on in-house legal counsel. In total, I&M's rate case expense is lower than both *NIPSCO* and *Duke*. Williamson Rebuttal, 33-35. The Company's rate case expense is based on actual experience in Indiana. Notably, the legal fee component of current rate case expense for services rendered in 2019-2020 is approximately 3% greater than that included in the Company's most recent rate case for legal services rendered in 2017-2018 where rate case expense was not challenged. Williamson Rebuttal 3-31.

The fact that I&M has structured its organization differently than other utilities does not demonstrate that its overall rate case expense is unreasonable. As Mr. Williamson pointed out, the I&M legal department does not have on staff a lawyer licensed to practice in Indiana. Williamson Rebuttal, 37. One would need to be hired in order for I&M to rely upon in-house counsel for this case. This is in contrast to the recent *NIPSCO Electric* and *Duke* rate cases, which did rely upon experienced in-house counsel licensed to practice in Indiana to lead their recent rate cases. As a result, their estimated outside counsel fees were lower. Both of those utilities, however, relied upon outside consultants for cost of service and rate design, and for both of them this element was the largest component of their total rate case expense. I&M relied upon internal resources for cost of service and rate design, and therefore had no rate case expense for this element. Further, Mr. Garrett did not factor the additional labor and benefits to hire the additional lawyer that would be necessary for Petitioner to have relied on in-house legal counsel. We reject Mr. Garrett's challenge to reasonableness of the Company's legal fees and overall rate case expense. We therefore find Petitioner's total estimated rate case expense to be reasonable and not excessive. However, we note on cross-examination, Mr. Thomas admitted that no settlement discussions occurred during the pendency of this proceeding. Tr. B-53-54. The Commission generally encourages parties to pursue settlement discussions in good faith. While we understand that settlement is not always possible, and may not occur among all parties, we are concerned that I&M made no attempts to discuss settlement, even at a cursory level. Without any attempts at settlement, there is no way of knowing whether rate case expense, and particularly legal expense, could have been lower. As such, in the future, should I&M fail to make any reasonable attempt at settlement negotiations in a rate case proceeding, the Commission will more carefully scrutinize the Company's proposed rate case expense. As to the amortization period, Mr. Garrett offered no explanation for why he believes three years to be more appropriate. Based upon the life of the current rates, we find Petitioner's two-year proposed amortization to be proper. Accordingly, we therefore accept Mr. Williamson's proposed two year amortization of rate case expense.

#### N. Taxes.

1. Excess Accumulated Deferred Federal Income Taxes (“EADFIT”).

(a) I&M. Mr. Williamson discussed the amortization of normalized (protected) and non-normalized (unprotected) EADFIT in connection with the Settlement Agreement approved in Cause No. 44967. Williamson Direct, 60. He said in that Cause, I&M agreed to reflect in the revenue requirement a total amortization of \$29.9 million for both protected and unprotected EADFIT, with actual amortization of the normalized EADFIT to be based upon the average rate assessment method (“ARAM”) and the amortization of the non-normalized EADFIT to be based on a period of six years. He stated the settlement in Cause No. 44967 also provided: “To the extent that the actual annual amortization differs from the estimated amount, the amortization of the non-normalized excess EADFIT will be increased or decreased to ensure that the total amortization of normalized and non-normalized excess EADFIT each year will be adjusted to “balance” the fluctuations in ARAM and ensure that the combined amortization each year equals \$29.9 million. *Id.* Mr. Williamson stated that this “balancing” methodology ensures both (a) that I&M follows ARAM for normalized excess EADFIT and therefore does not commit a normalization violation and (b) that I&M’s total amortization each year equals \$29.9 million as agreed in the settlement. *Id.*, 61.

Mr. Williamson explained that while the total amortizations levels is the same as the settlement, the normalized EADFIT amortization has been less than estimated in that Cause, resulting in faster amortization of the non-normalized EADFIT than anticipated. Williamson Direct, 61. Mr. Williamson testified that I&M estimates it will run out of the non-normalized EADFIT as early as 2022. *Id.*, 60-61. Mr. Williamson clarified how the Company would continue the “balancing” methodology in the settlement approved in Cause No. 44967. *Id.*, 62.

To address this issue and avoid a normalization violation, he said that once the non-normalized excess EADFIT is fully amortized, I&M is requesting accounting authority to defer and record as a regulatory asset the annual difference between (i) the annual amortization of normalized and non-normalized excess EADFIT reflected in base rates (*i.e.*, \$29.9 million in this case) and (ii) the actual annual normalized ADFIT amortization required by ARAM. Williamson Direct, 62. He stated the deferral will begin once the non-normalized EADFIT has been fully amortized. *Id.*, 62.

(b) OUCC. Witness Blakley opposed the deferral request as stated and proposed an alternative. The OUCC proposed that when the unprotected EADFIT has been fully amortized, I&M should change rates through a compliance filing to reflect the higher cost of service and thereafter, base the deferral only on the differential amortization of protected. Blakley, 7-9.

(c) Intervenors. IG witness Gorman opposed the indeterminable amount of the possible regulatory asset given the undefined time during which the deferral could persist. He proposed a determination on the deferral authority wait until the next rate case and that base rates be adjusted when the unprotected EADFIT has been exhausted. Gorman, 43-44. Joint Municipal Group witness Cannady recommended the Company reduce the annual amortization of EADFIT from \$29.9 million to \$28.8 million. She also objected to the Company’s proposal to establish a regulatory asset and associated carrying charges. Cannady, 3, 6-10.

(d) Rebuttal. Mr. Williamson agreed that there is uncertainty as to when non-normalized EADFIT will be fully amortized and explained that the Company's proposed mechanism addresses this uncertainty, while ensuring customers fully benefit from EADFIT going forward and the intent of the settlement agreement in Cause No. 44967 continues to be carried out. To respond to the IG and OUCC testimony, Mr. Williamson proposed a modification to the Company's original proposal. Williamson Rebuttal, 57. Mr. Williamson proposed the Commission approve the following ongoing ratemaking treatment:

- (A) Once non-normalized (unprotected) EADFIT is fully amortized, I&M makes a compliance filing to confirm the occurrence.
- (B) Establish a rider to recognize the increased cost of service resulting from the removal of the Test Year level of non-normalized EADFIT which would remain in place until I&M's next rate case. The filing would establish a charge that recognizes the impact on non-normalized EADFIT being fully amortized, by utilizing the final Commission approved revenue requirement from the instant proceeding. Holding all other results of the Commission-approved revenue requirement constant and removing the unamortized non-normalized EADFIT balance from rate base and the annual level of non-normalized excess EADFIT amortization, a new revenue requirement will be determined. The difference between the new revenue requirement described above and the Commission-approved revenue requirement in the instant proceeding would be the basis for the change in rates.
- (C) Establish rider rates using two-part rates for demand metered customers, and an energy only rate for non-demand metered customers.
- (D) Authorize I&M to defer the difference on an ongoing basis between actual EADFIT amortization and the level embedded in base rates once the non-normalized EADFIT balance is fully amortized.

*Id.*, 59-60. Mr. Williamson explained that this proposal ensures that customers continue to receive the benefits of EADFIT going forward, maintains the intent of the settlement agreement in Cause No. 44967 allows the Company to continue to comply with tax normalization rules and addresses the concerns of the IG and OUCC by minimizing the level of deferred costs. *Id.*, 60. He added that the rider mechanism will provide a more efficient way to addressing this singular topic, rather than revise all the applicable rates in I&M's tariff book. *Id.*

As to Ms. Cannady's position, Mr. Williamson responded there is no need to revisit the settlement that was reached in Cause No. 44967, as it can be fully accommodated in this case. He also confirmed that Petitioner is not seeking any carrying charges on the deferred asset. Williamson Rebuttal, 60-63.

(e) Discussion and Finding. The parties are in agreement that something must be done upon completion of amortization of unprotected EADFIT. Otherwise, we believe a normalization violation is risked. In light of the objections to the indefinite nature of the deferral authority as originally proposed, the most reasonable response is the mechanism proposed by I&M on rebuttal. Accordingly, we find that upon completion of amortization of unprotected EADFIT, I&M should defer the difference between the total EADFIT amortization reflected in base rates (as the same may be adjusted by the rider mechanism we are approving)

and actual amortization expense based on ARAM for protected EADFIT. I&M shall also make a compliance filing confirming that all non-normalized (unprotected) EADFIT has been amortized and submitting a rider that will reflect the removal of the test year level of non-normalized (unprotected EADFIT) amortization as proposed by Mr. Williamson. As Mr. Williamson proposed, the rider should also reflect the removal of unprotected EADFIT from rate base. Finally, we find the two-part mechanism for demand metered customers and energy only mechanism for all other customers as proposed by Mr. Williamson is reasonable and is approved.

## 2. Utility Receipts Tax.

(a) Industrial Group. Industrial Group Witness Gorman testified that Utility Receipts Tax (“URT”) should be removed from the gross revenue conversion factor and recovered separately as its own line item on the customer bill. Gorman, 9.

(b) Rebuttal. Mr. Williamson did not disagree in theory with Mr. Gorman’s proposal, noting that it would only change “how” the cost is recovered and not “if” the cost is recovered. Nevertheless, he stated Petitioner is not prepared to implement this proposal at this time and would need time to determine how this change would be structured and billed. Williamson Rebuttal, 69.

(c) Discussion and Finding. We find Mr. Gorman’s proposal somewhat confusing because, as Mr. Williamson pointed out, adopting it would not affect whether the URT cost is recovered, only how it is recovered and reflected on customer bills. We find it curious because it should not affect the total bills that customers pay. We agree that such a proposal merits further study before it could be ordered in the context of a general rate case. Further, since URT is paid by all public utilities, our decision should not apply to only one utility and should instead be the subject of further study across all industries before implementation. Accordingly, we decline to accept Mr. Gorman’s proposal.

## O. Vegetation Management.

1. I&M. Mr. Isaacson summarized the Company’s vegetation management program reflected in the Capital Forecast Period and Test Year O&M. He explained the program involves ongoing work on moving away from a reactive approach to managing vegetation to a systematic, cycle-based approach to managing vegetation. Isaacson Direct, 13. He said I&M is on schedule to complete the initial four-year period as planned. He summarized results for 2018 and the work plan for 2019-2022. *Id.* at 13-14. He also identified the drivers and benefits of I&M’s vegetation management program. *Id.* at 14-15.

2. OUCC. Mr. M. Garrett stated the Test Year forecast for vegetation management is higher than its actual spending levels for most of the prior five years. He argued the higher level of spending in 2018 did not justify I&M’s request for ongoing recovery at an elevated level. M. Garrett, 47. He asserted the higher expenditures are largely related to remedial work that should have been completed in prior years, that I&M has not historically spent the projected amounts from its last case, and that the Michigan Commission recently raised similar concerns regarding I&M’s vegetation management plan. *Id.*, 48-49. He recommended using a 5-

year historical average of actual expenditures, which would reduce vegetation management expense by \$5,803,400. *Id.*, 50-51.

3. Rebuttal. Mr. Isaacson explained I&M began its cycle-based vegetation management program in 2018 with the first year of the planned four-year period (2018-2021) to establish a regular four-year vegetation management cycle. Isaacson Rebuttal, 13. He said it is unreasonable to compare I&M's forecasted Test Year level of vegetation management expenditures to the five-year historical average because I&M began its new four-year vegetation management cycle in 2018. He testified the significant reduction proposed by Mr. Garrett would hamper the Company's implementation of a proactive vegetation management approach and could eliminate the significant customer reliability benefits that a proactive approach would bring. *Id.* at 14. He disagreed I&M is "catching up" on deferred maintenance as asserted by Mr. Garrett. He also disagreed I&M diverted funds allocated to vegetation management to I&M's bottom line and pointed out I&M's actual vegetation O&M expenditures in 2018 were actually *greater* than I&M's forecasted amount and *greater* than the Test Year level of O&M reflected in the settlement approved in Cause No. 44967. *Id.* at 15-16. He said Mr. Garrett's reference to a Michigan Order is distinguishable from the present case and raised issues not shown to be applicable to I&M's Indiana jurisdiction. *Id.* at 17.

4. Discussion and Finding. In I&M's last rate case, we noted that I&M "committed to achieving a four-year trim cycle." *Indiana Michigan Power Co.*, Cause No. 44967, 28 (IURC 5/30/2018). The record shows I&M began its proactive four-year vegetation management cycle in 2018 and that the actual vegetation management expenditures in 2018 reflect this commitment. I&M experienced a decline in distribution tree-caused SAIDI by 12% in 2018, confirming this approach produces positive results. The OUCC proposes to reduce the level of vegetation management expense to a level below that necessary for I&M to continue to implement the initial four-year cycle. We find the OUCC's recommendation would essentially require I&M to go back to a more reactive approach to vegetation management that would likely result in an increase in outages and a decrease in reliability. Given that cycle-based vegetation management programs are widely acknowledged in the industry as the most effective way to reduce vegetation-related outages, we find the OUCC's proposal unacceptable. The record shows I&M's Test Year level of vegetation management expense is consistent with that experienced in 2018 and with year-to-date results in 2019. Isaacson Rebuttal, 16, Figure DSI-R1. Accordingly we find Mr. Garrett's proposed adjustment should be rejected.

## **11. Financial Forecast.**

1. I&M. Ms. Heimberger presented I&M's 2020 Test Year financial forecast and discussed the forecast process. Heimberger Direct, 2. She explained the forecasting process used in this proceeding is the same that was used in I&M's last basic rate case, Cause No. 44967. *Id.*, 4-5. She discussed the major components of I&M's financial forecast and identified the other I&M witnesses supporting the O&M and capital expenditure work plan activities. *Id.*, 5-10. She also presented and discussed the forecasted operating revenues, generation forecast, O&M, depreciation and amortization, taxes, plant in service, construction work in progress, and accumulated depreciation. *Id.*, 10-23. She said the projected values she provided are reasonable and accurate and reflect the income statement and balance sheet activity likely to occur during the Test Year. *Id.*, 28.



Mr. Burnett testified the Test Year load forecast is reasonable and was derived using widely accepted modeling techniques based on the best information that was available at the time it was completed. Burnett Direct, 18. He described the load forecasting methods used by I&M for short-term and long-term kWh forecasting and explained I&M uses processes that take advantage of the relative strengths of each methodology. *Id.*, 5-8. He said the Test Year forecast assumes normal weather conditions and is adjusted for the impacts of I&M's DSM and EE programs that are approved by the Commission. *Id.*, 9-11. He said I&M's load forecast methodology is proven to produce accurate and reliable projections that are useful for planning and setting rates. *Id.*, 11. He said the average accuracy of the budget load forecasts for I&M since 2008 has been within 0.3% on a weather normalized basis. *Id.*, 11-12; Figure CMB-2. He explained the Test Year forecast incorporates information from Moody's Analytics, which is predicting the end of the current business cycle and the start of the next recession in the year 2020. *Id.*, 13-14.

2. Intervenors. Mr. Mancinelli stated I&M should remove the recession assumption from its 2020 Test Year load forecast because the assumption is not sufficiently fixed, known, or measurable. Mancinelli, 5, 31. He argued I&M's ~~recession assumption does not meet the "fixed, known, and measurable" standard~~ has the burden of proof to show its Test Year assumptions are reasonable, and that I&M provided no definitive information as to the timing of the recession. *Id.*, 31-33. He referenced an April 2019 economic outlook prepared for the State of Indiana, which he said does not indicate a recession. *Id.*, 34.

3. Rebuttal. Mr. Burnett stated I&M's load forecast reflects the base economic forecast from Moody's Analytics, a trusted and reputable provider of economic forecast data. He explained no "adjustment" was made to the forecast to account for the economic downturn and that Mr. Mancinelli failed to provide data to support such an adjustment. Burnett Rebuttal, 2-5. He pointed out the economic outlook provided by Mr. Mancinelli supports, rather than contradicts, the general economic assumptions used by I&M in its load forecast. *Id.*, 5-7.

Mr. Burnett said Mr. Mancinelli's testimony erroneously compares annual incremental DSM savings for the historical data to a cumulative number for 2020, undermining his claim that the DSM assumptions in I&M's load forecast are too high. Burnett Rebuttal, 13-15. Finally, Mr. Burnett showed that I&M's updated June 2019 load forecast for 2020 is 1.2% lower than the forecast used in this case, underscoring the reasonableness of the Test Year forecast. *Id.*, 10-12. At the hearing, Mr. Burnett indicated the newest update to the load forecast shows 2020's load projected to be 1.4% below the level used in this proceeding. Tr. G-109-10.

4. Discussion and Finding. ~~We begin our discussion by noting~~ I&M has filed this case under Section 42.7 utilizing a forward-looking test year. The "fixed, known, and measurable" standard only applies to a historic test year, or the historic portion of a hybrid test year, ~~and so we reject Mr. Mancinelli's attempt to apply this standard to I&M's Test Year.~~ Ind. Code § 8-1-2-42.7(d). However, we do not believe that the statutory intent behind the use of future test years for ratemaking purposes is that the Commission simply must accept whatever forecasts the utility provides without any regulatory scrutiny. The Commission remains obligated to set rates under Ind. Code § 8-1-2-4 that are "reasonable and just". I&M has the burden of proof to show the reasonableness of its economic forecast, which is included in the substantive



basis for its proposed rates. The Commission, in its broad discretion, can make adjustments to a utility's future test year forecasts if we find them to be unreasonable. ~~Mr. Mancinelli's emphasis on the word "recession" and the specific timing of an economic downturn ignores the broader point that most indicators are suggesting the economy is slowing down. We note that the economic outlook cited by Mr. Mancinelli himself identifies rising risks of a downturn after 2019, which is consistent with the Moody's Analytics base forecast relied upon by I&M. Attachment JAM-7 at 10; Burnett Rebuttal, 5-7.~~

Economic forecasts are speculative by their very nature, particularly the farther in the future they reach. Mr. Burnett's testimony included no specific details about the timing or severity of a possible recession. In fact, his testimony indicated that some economists predict a recession in 2021, which would miss the Test Year in this case entirely. Burnett Direct, 14. DSM forecasts, in particular, attempt to quantify actions taken by consumers to reduce their electric demand that are difficult to quantify. A future test year which included pessimistic economic forecasts and inflated DSM estimates results in a reduced load forecast, which in turn increases customer rates. It was not until rebuttal that ~~the~~ the reasonableness of I&M's load forecast ~~was~~ is also borne out by I&M's updated load projections, which showed 2020 load forecasted to be 1.4% lower than the Test Year load forecast used in this case. Tr. G-109-10. ~~While Mr. Mancinelli proposes the load forecast be adjusted, he failed to provide substantial evidence as to what that adjustment should be. With respect to his proposal to rerun the load forecast using historical DSM information, the record shows Mr. Mancinelli erroneously compared the wrong data points and that the load forecast reasonably used I&M's IRP as the source for long-term DSM/EE savings assumptions. Accordingly~~ In the absence of any substantial evidence regarding specifically how I&M's load forecast should be adjusted, we find I&M's Test Year forecast to be reasonable. We instruct I&M in its case-in-chief in any future base rate case to compare forecast period economic and DSM data to actual data for each of the three most recent consecutive years preceding the test year.

**12. Net Operating Income at Present Rates.** Based upon the evidence and the determinations made above, we find I&M Test Year operating results under its present rates are as follows:

Operating Revenues	\$	1,501,500,440
Less: O&M Expenses	\$	940,063,648
Depreciation/Amortization	\$	320,298,525
Other Taxes	\$	1,310,661
State Income Taxes	\$	84,099,835
Federal Income Taxes	\$	(918,020)
Income Tax Credit Adjustments	\$	(17,650,615)
Total Operating Expenses	\$	1,327,204,034

Net Operating Income (“NOI”)	\$ 174,296,406
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In summary, we find that I&M’s annual net operating income under its present rates for electric utility service would be approximately \$174,296,406, which is insufficient to represent a reasonable return. We therefore find that I&M’s present rates are unreasonable. Accordingly, it is both reasonable and necessary for new rates and charges to be established.

**13. Authorized Revenue Requirement.** On the basis of the evidence presented, we find that I&M should be authorized to increase its basic rates and charges to produce additional operating revenue of approximately \$~~149,740,006~~~~162,134,257~~. This revenue is reasonably estimated to afford I&M the opportunity to earn net operating income of approximately \$~~281,556,473~~~~290,672,575~~, as follows:

Operating Revenues	\$ 1,659,725,479
Less: O&M Expenses	\$ 940,400,034
Depreciation/Amortization	\$ 320,298,525
Other Taxes	\$ 1,310,661
State Income Taxes	\$ 7,254,620
Federal Income Taxes	\$ 13,288,955
Total Operating Expenses	\$ 1,369,052,904
Net Operating Income (“NOI”)	\$ <del>281,556,473</del> <del>290,672,575</del>

Calculation of Authorized Increase in Revenue:

Rate Base	\$ 4,918,317,686
Required Rate of Return	5. <del>729</del> 1%
Allowable Electric Operating Income	\$ <del>290,672,575</del> <del>281,556,473</del>
Less: Adjusted NOI at Present Rates	\$ 174,296,406
Deficiency in Electric Operating Income	\$ <del>116,376,169</del> <del>107,260,067</del>
Times: Revenue Conversion Factor	1.3596

Jurisdictional Revenue Deficiency	\$	<del>158,225,039</del> 145,830,788
Remove Transmission Owner Costs, <sup>10</sup>	\$	3,909,218
Revenues <sup>10</sup>		
Total Required Rate Relief Before Phase-In Credit	\$	<del>162,134,257</del> 149,740,006
Less: Current Revenue for Ongoing Riders	\$	221,393,319
Plus: Proposed Rider Revenue	\$	221,646,844
Total Rate Change Before Phase-In Credit	\$	<del>162,387,782</del> 149,993,531

We further approve the phase-in of I&M's rates as proposed by I&M, which was not challenged by any party and which we find to be reasonable. More specifically, when I&M's new base rates are first effective, they will include both the "IMMDA Credit" of \$46,442,922 identified by Ms. Duncan on page 20 of her direct testimony and a "Forecasted Plant Credit" to reflect forecasted plant additions during the Test Year.<sup>11</sup>

On June 1, 2020, the IMMDA Credit will automatically expire and the full Forecasted Plant Credit will continue. The Forecasted Plant Credit will remain in effect until I&M's final compliance filing is made on or after January 1, 2021. In this way, I&M's rates will not reflect forecasted Test Year plant additions until they are placed in service and are used and useful in the provision of service for customers. Duncan Direct, 21.

We find Phase III rates should utilize the same compliance filing process as "Phase II" rates in Cause No. 44967. I&M shall certify to this Commission its net plant at December 31, 2020 and thereafter calculate the resulting Phase III rates. For purposes of the Phase III certification, I&M shall use the forecasted Test Year end net plant of \$4,918,317,686 approved above. The Phase III rates shall go into effect on the date that I&M certifies its Test Year end net plant, or January 1, 2021, whichever is later. The net plant for Phase III rates shall not exceed the lesser of (a) the forecasted Test Year end net plant approved herein or (b) I&M's certified Test Year end net plant. I&M shall serve all parties with its certification. The OUCC and intervenors shall have 60 days from the date of certification to state objections to I&M's certified Test Year end net plant. If there are objections, a hearing shall be held to determine I&M's actual Test Year end net plant, and rates will be trued-up (with carrying charges) retroactive to January 1, 2021 (regardless of when Phase III rates go into effect).

#### **14. Cost of Service and Revenue Allocation.**

##### **A. Jurisdiction Separation Study.**

<sup>10</sup> As-filed amount shown. Final value will change consistent with approved calculation methodology when approved changes are flowed through class cost-of-service. Nollenberger Direct, 5.

<sup>11</sup> While I&M originally calculated a Forecasted Plant Credit of \$43,051,354 (Duncan Direct, 20), we note the approved Forecasted Plant Credit will be slightly different as a result of the rate base approved herein.

1. I&M. Ms. Duncan presented the jurisdictional separation study, which allocates the total Company rate base, revenues, and expenses to the Indiana retail jurisdiction. She said the same overall methods employed to develop the jurisdictional study in Cause No. 44967 were used to develop the jurisdictional study in this case. Duncan Direct, 6-7. She explained adjustments were made to annualize known interruptible customer load changes and the loss of wholesale load associated with the Indiana and Michigan Municipal Distributors Association (“IMMDA”) members effective June 1, 2020. *Id.*, 9-10. Mr. Thomas stated all but one of the IMMDA contracts will expire on or before June 1, 2020, with the last contract to expire on or before June 1, 2026. Thomas Direct, 6. Mr. Williamson explained the Company’s proposed phase-in of base rates would ensure that these contracts continue to benefit retail customers until the contracts expire. Williamson Direct, 5-6, 19, 24. Ms. Duncan also supported new demand and energy allocation factors required as a result of Michigan’s Electric Customer Choice program. Duncan Direct, 10.

2. Intervenors. IG witness Gorman testified I&M did not take reasonable steps to retain the IMMDA load or find replacement load. He said the additional capacity allocated to Indiana retail customers is not needed and proposed to make permanent \$46.44 million in offsets to I&M’s cost of service that are currently received by I&M from its expiring IMMDA contracts. Gorman, 8-9, 34-38. Joint Municipal witness Mancinelli stated fixed costs associated with the IMMDA load loss should be recovered within the wholesale jurisdiction, not shifted to I&M’s retail jurisdictions. Mancinelli, 9-11, 59. Mr. Mancinelli noted that under FERC’s rules at 18 C.F.R. § 35.26(b)(1) under FERC Order 888,<sup>12</sup> I&M had the right to recover stranded costs in the IMMDA contracts. Mancinelli, 21-26. He reasoned that because I&M did not avail itself of that right by including an exit fee in those contracts or other stranded cost recovery remedies, I&M should not be allowed to recover costs associated with this IMMDA wholesale load loss through retail customers. *Id.* He contended I&M is using retail customers as a hedge against lost load attributable to the wholesale business. He said this practice should not be allowed, as I&M bears no risk and therefore has little motivation to replace lost load. Mancinelli, 19. Mr. Mancinelli stated I&M experienced some load loss and stranded costs in Michigan as a result of the Michigan Electric Customer Choice program, and did not shift the fixed costs associated with Michigan firm load loss to other jurisdictions. Mancinelli, 26. He said he agreed with I&M’s treatment of Michigan load loss in the jurisdictional separation study and said this treatment is consistent with his recommendation pertaining to the loss of firm wholesale load, which he said should be borne by wholesale customers. *Id.*, 26-28. Mr. Cearley stated I&M should not be allowed to decrease test year revenues for loss of wholesale load until it has reasonably demonstrated what it has done to either retain or replace this lost load beyond just making claims of supporting economic development. Cearley, 9.

3. Rebuttal. Ms. Duncan explained that the jurisdictional allocation should reflect the load conditions expected during the period the rates established in this Cause

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<sup>12</sup> Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), order on reh’g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh’g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh’g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff’d in relevant part sub nom. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), aff’d sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

will be in effect. She disagreed her jurisdictional separation study is “raising rates” on customers. Duncan Rebuttal, 3. She explained Mr. Mancinelli’s and Mr. Gorman’s treatment of costs associated with serving the Company’s retail and wholesale customers is not consistent with jurisdictional cost allocation principles and deviates from the historical practice. Duncan Rebuttal, 2.

Ms. Duncan disagreed with Mr. Mancinelli’s categorization of these costs as being “stranded” because the capital assets related to these costs are still used and useful to I&M customers. Duncan Rebuttal, 9. She also disagreed with Mr. Mancinelli’s assertion that I&M’s treatment of the IMMUDA load is inconsistent with its treatment of the Michigan Choice customers. *Id.* She said all costs that are related to the wholesale jurisdiction have been allocated using the allocation factors proposed in this case, which includes the loss of the IMMUDA load. *Id.*, 9-10. Similarly, she said all costs that are affected by Michigan Customer Choice have been allocated using the “excluding shopping” allocation factors proposed in this case. She said the cost allocation method used in both circumstances (*i.e.*, the IMMUDA load loss and the Michigan Choice customers) is in accordance with the cost causation principle, which ensures customers are only paying for the costs they are responsible for incurring and does not leave so-called “stranded costs” for the remaining Michigan retail and wholesale customers to account for. *Id.*, 10-11. On cross-examination, Ms. Duncan admitted to not having a “thorough knowledge” of FERC’s Order 888, nor was Ms. Duncan aware that the order in Cause No. 38728 that she referenced as a similar model for the treatment of lost wholesale load occurred prior to the issuance of Order 888. Tr. D 6-7.

Mr. Thomas testified the Company’s current IRP shows that regardless of when the Rockport Unit 2 lease terminates, I&M will face a capacity gap of approximately 500 MW. Thomas Rebuttal, 28. He stated Mr. Gorman’s contention that the generation that has been used to serve the IMMUDA load is not used and useful in the provision of retail service takes an unreasonably shortsighted perspective in that it fails to recognize that capacity additions or subtractions will rarely exactly match changes in load requirements. Thomas Rebuttal, 28.

Mr. Thomas said Mr. Mancinelli’s contention that the Company should have done more to replace the IMMUDA wholesale load is not supported by any evidence and is mere conjecture. Thomas Rebuttal, 29. Mr. Thomas explained I&M actively negotiated with the IMMUDA members to find creative alternatives that would allow the contracts to be renewed or reformed. He said I&M and the expert and experienced generation marketing team at AEP made best efforts to avoid the termination of the agreements. He stated since receiving the notices that the contracts will be terminated, I&M explored options available in the wholesale market in anticipation of the capacity and energy becoming available. Mr. Thomas stated if additional revenues result from those activities, the Off System Sales tracker will flow the vast majority of the margins back to customers. Thomas Rebuttal, 29. He added the Company has aggressively pursued the development of economic growth in its communities and have had success doing so. Thomas Rebuttal, 29. He therefore disagreed with the implication that I&M was passive in reacting to the termination of the IMMUDA contracts.

4. Commission Discussion and Findings. I&M provides retail service in Indiana and Michigan. Customers in each retail jurisdiction benefit from the combined scale and scope of the integrated utility systems which also allows I&M to engage in both wholesale

~~purchases and sales of electric power. Power not used to serve retail customers is sold at wholesale rates to other interconnected electric utilities, such as municipally owned systems. The margins from such wholesale power contracts are used to reduce the retail revenue requirement. In each general rate case, a jurisdictional separations study is performed to separate the Company's Test Year cost of service among these three jurisdictions. When the Company loses or adds load, regardless of jurisdiction, the Company's test year costs are spread over the smaller or larger customer base using a jurisdictional separation study. See Duncan Rebuttal, 8.~~

~~While the Intervenor's did not challenge the allocation and assignment methods employed in Ms. Duncan's jurisdictional separation study, they oppose adjustment of the Company's Test Year to reflect the load that will exist during the term the rates set in this proceeding will be in effect. IMMDA members have received full-requirements electric service from I&M for more than fifty years. Jt. Mun. Ex. 5. IMMDA members are municipal utilities in their own right, and thus, under FERC Order 888's requirements for open access transmission service, could obtain wholesale electric service from another service provider any time after 1994. The record shows that the IMMDA customers elected to end their wholesale contracts consistent with the terms and conditions of their contracts with I&M. Pet. Ex. 44 at 1 (I&M Response to Commission Request for Information). This change will occur during the Test Year. The record also shows that the Company's generation continues to be used and useful in the provision of service to Indiana customers. Thomas Rebuttal, 28. To the extent that additional off-system sales are made once the IMMDA contracts expire, the Off System Sales tracker will flow 95% of the OSS margins back to the benefit of retail customers. Duncan Rebuttal, 4; Williamson Direct, 48-50. While Mr. Mancinelli argued I&M treated the IMMDA load inconsistently compared to the Michigan Choice customers, the record shows I&M's jurisdictional separation study treated both consistently and in accordance with cost causation principles. Duncan Rebuttal, 10-11.~~

In its rulemaking implementing Order 888, FERC acknowledged that open access and competition in the wholesale market would result in stranded costs.<sup>13</sup> FERC recognized that public utilities had built up generating capacity for many years with the expectation that such capacity would be used and useful for the provision of service to its captive wholesale customers. When those wholesale customers were no longer captive as a result of FERC's requirement that public utilities provide Open Access Transmission Tariffs ("OATTs"), FERC recognized that it had to provide a mechanism for recovery of those stranded costs. In Order 888, FERC stated that "If a former wholesale requirements customer...uses the new open access to reach a new supplier, we believe that the utility is entitled to recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime . . . ."<sup>14</sup>

~~We find Mr. Mancinelli's assertion that I&M should have included provisions to address what he called "stranded costs" associated with serving these wholesale customers to be unsupported by the record. The record shows that the contract negotiations between I&M and the IMMDA members were conducted at arms' length, were extensive, and very contentious. Tr. J-64-65.~~

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<sup>13</sup> See Notice of Proposed Rulemaking, *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs. ¶ 32,507 at 32,863-64, 59 Fed. Reg. 35,274 (1994).

<sup>14</sup> Order 888, ¶ 31,036 at 31,789.



Mr. Williamson explained during cross-examination that the IMMDA customers were not required to enter into these contractual arrangements, and had the contracts contained provisions to address Mr. Mancinelli's so-called "stranded costs", it may have resulted in those contracts never being executed in the first place. *Id.* This argument fails to recognize that I&M had an opportunity when wholesale markets were opened to competition to petition FERC for a unilateral stranded cost amendment, and FERC had the authority to approve such an amendment in the public interest, regardless of whether the IMMDA members agreed with the amendment. FERC's rules adopted under Order 888 note that "...it is in the public interest to permit public utilities to seek unilateral amendments to add stranded cost provisions if the contracts do not in essence forbid such recovery by [already] containing exit fees or other explicit stranded cost provisions."<sup>15</sup> ~~Given this, we conclude I&M reasonably negotiated its wholesale contracts with the IMMDA members, to the benefit of I&M's other customers.~~

We disagree with Ms. Duncan that I&M's fixed costs once recovered through the IMMDA formula rate and allocated to retail customers in the Jurisdictional Separation Study are not stranded costs. FERC defines wholesale stranded costs as:

Wholesale stranded cost means any legitimate, prudent, and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) A retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.<sup>16</sup>

Thus, stranded costs are costs related to providing wholesale service to wholesale requirements customers that no longer receive such service from the incumbent utility provider. That is exactly what is happening with the IMMDA customers. Absent FERC Order 888, the IMMDA members would either have to build their own generating capacity to serve themselves (a proposition which is likely cost-prohibitive), or they would have to remain captive customers of I&M.

Since we have found that by FERC's very definition, costs associated with I&M's lost IMMDA load will be stranded, we now turn to what relief I&M could have pursued to recover those stranded costs. FERC's stranded cost regulations allowed I&M, prior to the expiration of any IMMDA contracts that were executed on or before July 11, 1994 that did not contain an exit fee or other explicit stranded cost provision, to petition FERC for authority to recover stranded costs either through: (1) an exit fee amendment to the requirements contract; or (2) through rates for wholesale transmission services to a departing wholesale requirements customer that uses the utility's open access transmission tariff to obtain power from a new generation supplier.<sup>17</sup> Given that I&M continued to serve the IMMDA load long after Order 888 and did not negotiate new

<sup>15</sup> Order 888, 61 Fed. Reg. 21540-01 at 21642, 1996 WL 239663(F.R.).

<sup>16</sup> 18 CFR § 35.26(b)(1).

<sup>17</sup> 18 C.F.R. §§ 35.26(c)(1)(v)(A) and (B).

the present contracts with IMMDA members until 2006, the Company had a reasonable expectation of continued service. The record is devoid of any evidence that I&M ever availed itself of options under Order 888 to either add a stranded cost provision to its full requirements contracts with IMMDA members, or to change its FERC approved transmission rates. I&M cannot now go to FERC for recovery, because FERC's rules consider the IMMDA contracts currently in effect as "new contracts" and the unilateral right to amend contracts to include stranded costs provisions only applied to contracts that were in effect on or before 1994.<sup>18</sup>

When I&M did not seek to unilaterally amend the IMMDA contracts to include an exit fee as permitted by FERC rules, it created a situation in the present case whereby retail customers potentially bear the impact of costs that they did not cause. In Order 888, FERC explained that the spreading of stranded costs to other customers "... might enable a wholesale customer to leave sooner than would the direct assignment approach, the departing customer would be able to do so only at the expense of others who had no responsibility for causing the legitimate, prudent and verifiable costs to be incurred." That is exactly what has happened in this case. IMMDA members are no longer going to be wholesale full-requirements customers of I&M, and I&M has no ability to recover additional costs from them. Rather than taking steps to ensure that the Company was able to recover costs from IMMDA members before they left I&M's system, the Company is now seeking to recover the IMMDA costs from its other customers which did not cause those costs. Both Indiana courts and the Commission have noted that "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."<sup>19</sup>

Utility rates must be just and reasonable. IC 8-1-2-4. For ratemaking purposes, the Commission may disallow any costs it finds imprudent or excessive.<sup>20</sup> I&M had an obligation to prudently manage its IMMDA contractual arrangements, and its failure to do so has incurred costs that retail customers did not cause and thus should not be required to bear. The Commission has found that utilities have an obligation to "...take all reasonable steps to mitigate to the maximum extent possible the total amount of stranded costs they seek to claim and to minimize the cost to be recovered from customers."<sup>21</sup> We find it was imprudent for I&M to wait until 23 years after FERC's Order 888 to take action with regard to recovery of stranded costs from IMMDA members. Therefore, we order I&M to revise its forecasted Test Year revenues to remove all fixed costs associated with service to IMMDA customers that it allocated to retail customers in the Jurisdictional Cost of Service Study.

~~The record also shows I&M undertook a number of steps to try and retain this load, including holding several meetings with individual IMMDA members, meeting with IMMDA leadership and then following up with the affected IMMDA customers describing the offer I&M~~

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<sup>18</sup> 18 C.F.R. § 35.26(b)(7) and (8). While the regulations approved in Order 888 were not finalized until 1996, those rules back-dated the definition of existing contracts to the date the Notice of Proposed Rulemaking was published in the Federal Register, which was July 11, 1994.

<sup>19</sup> *Citizens Action Coal. of Ind., Inc. v. Indianapolis Power & Light Co.*, 74 N.E.3d 554, 561 (Ind. Ct. App. 2017).

<sup>20</sup> *City of Evansville v. Southern Ind. Gas and Elec. Co.*, 339 N.E.2d 562, 569 (Ind. Ct. App. 1975).

<sup>21</sup> *In the Matter of the Petition of the Town of Hometown*, Cause No. 44519 (IURC May 20, 2015), citing *Commission Inv. of GTE*, Cause No. 40618 (IURC May 7, 1998); *Heartland Gas Pipeline, LLC*, Cause No. 42729 (IURC Oct. 10, 2005); and *Comm'n Inv. of Smart Grid Investments*, Cause No. 43580 (IURC Dec. 16, 2009).

~~had made and the fact that IMMIDA leadership had rejected the offer on behalf of the members. Pet. Ex. 44 at 1 (I&M Response to Commission Request for Information). Mr. Thomas further described the efforts made by both I&M and its AEP generation marketing team to explore options available in the wholesale market. Thomas Rebuttal, 29. The substantial evidence presented by I&M demonstrates that I&M acted reasonably in response to the IMMIDA customers' decision to terminate their wholesale contracts. As further discussed below, I&M has also proposed the continuation of existing economic development programs and the implementation of additional programs designed to address the specific needs of its service area. The intervenor witnesses do not identify what additional steps I&M should have taken, or otherwise show that the steps I&M did take were inadequate.~~

~~Accordingly, based on the record as a whole, we conclude I&M's forecasted Test Year revenues appropriately reflect the expiration of the IMMIDA wholesale contracts and no further adjustment is warranted. Moreover, the record shows that I&M's jurisdictional separation study in this case was performed consistent with the studies performed in I&M's prior cases. Accordingly, we approve I&M's jurisdictional separation study.~~

## **B. Class Cost of Service and Revenue Allocation.**

1. I&M. Mr. Spaeth, presented Petitioner's class cost-of-service study at present rates, Attachment DEH-1, which allocates the total Indiana retail jurisdiction rate base, revenues and expenses to each rate schedule. He explained the cost allocation methodology used in the class cost-of-service study assigns costs among the customer classes in a fair and equitable manner based on principles of cost causation. Spaeth Direct, 2-3.

Mr. Spaeth testified the Company is proposing to continue using the 6 coincident peak ("6 CP") demand allocator, which assigns costs based on each customer classes' contribution to three summer and three winter months in the Test Year. Spaeth Direct, 12. He stated distribution plant is classified as demand- and customer-related and allocated to the customer classes using factors based on demand levels or number of customers. He explained classifying services and meters as customer-related (and primary and secondary poles, lines, and transformers as demand-related) has been accepted before this and other Commissions and is consistent with cost causation principles. Spaeth Direct, 15-16.

2. OUCC. OUCC witness Watkins opposed the Company's use of a 6 CP demand allocator for production and transmission plant. He proposed the Company allocate production plant on either a Peak & Average, 12 CP, or Base-Intermediate-Peak method and recommended a 12 CP demand allocation for transmission plant. Watkins Direct, 33. Mr. Watkins' cross-answering testimony opposed the IG, South Bend and Joint Municipals' proposals to use either a 3 CP, 4 CP, or 5 CP demand allocation method and recommended their proposals related to distribution plant be rejected. Watkins Cross-Answering, 9.

3. Intervenors. IG witness Phillips proposed the Company allocate its production plant and transmission plant on either a 5 CP (PJM Peak Load Contribution) or 4 CP summer method. He said if the 6 CP method is retained, the Commission should include a customer component for the allocation of distribution system costs using the minimum system approach, particularly for accounts 364 through 368. Phillips Direct, 16. In his cross-answering

testimony, Mr. Phillips responded to Mr. Wallach's and Mr. Watkins' energy-related cost allocation proposals.

Joint Municipals witness Mancinelli recommended the Company allocate both production and transmission plant on either a 4 CP or 5 CP method based on his belief that I&M is a summer peaking utility. Mancinelli, 38-40.

CAC-INCAA witness Wallach proposed the use of an energy-weighted demand allocation methodology (Equivalent Peaker) for the allocation of production plant. Mr. Wallach's cross-answering testimony opposed the IG and South Bend recommendations that I&M rely on minimum-system methods to classify distribution costs.

South Bend witness Seelye recommended the use of a 3 CP (summer) methodology for allocating production plant, transmission plant, and certain distribution capacity costs. He also proposed to classify a portion of distribution accounts 364 through 368 as customer-related. Seelye, 2-3, 11, 14. In his cross-answering testimony, Mr. Seelye responded to the testimony of Mr. Watkins, Mr. Wallach, and Mr. Phillips.

Kroger witness Bieber's cross-answering testimony recommended the Commission reject the OUCC and CAC's alternative class cost of service studies. He further recommended the use of a minimum distribution system method to classify certain distribution plant costs.

4. Rebuttal. Mr. Spaeth explained an energy-weighted demand allocator should not be used because it does not recognize the fixed nature of production plant costs, which do not vary based on the level of energy consumption. Spaeth Rebuttal, 3. With respect to the OUCC's 12 CP proposal and the Intervenor's alternative 3 CP, 4 CP and 5 CP demand allocation methodologies, Mr. Spaeth explained how these approaches fail to recognize that the Company's load profile shows I&M continues to be a summer and winter peaking utility. Spaeth Rebuttal, 4-10.

Mr. Spaeth also responded to the OUCC and Intervenor proposals regarding transmission and distribution plant allocation and explained how I&M's approach reflects the Company's standard engineering practice to plan its distribution facilities to meet the maximum expected demand on each component of the system. Spaeth Rebuttal, 11-14.

## 5. Commission Discussion and Findings.

(a) Demand Allocation Methodology. I&M proposed to classify electric generation production plant as 100% demand-related and allocate it to the various rate classes based upon the 6 CP monthly loads for the three summer months of June, July, and August and the three winter months of December, January, and February. This Commission approved the same demand classification and 6 CP allocation methodology for production plant in I&M's 2013 rate case, Cause No. 44075, 2013 WL 653036, 303 P.U.R.4th 384 (IURC 2/13/2013), and its 1993 rate case, Cause No. 39314, 1993 WL 602559 (IURC 11/12/1993). In *PSI Energy, Inc.*, we held that a change in cost allocation methodology can have significant impacts on customer classes and, thus, such a change should not be lightly undertaken, especially where so much of the plant was in service at the time of the utility's last rate case, and costs were assigned on the same basis in that case. Cause No. 42359, p. 102, 2004

WL 1493966 (IURC 5/18/2004). No operational changes have been identified by the parties that would warrant a departure from I&M's long-standing 6 CP approach.

The record shows the energy-weighted demand allocation methodologies proposed by the OUCC and CAC-INCAA do not recognize the fact that production plant costs are fixed in nature and exist regardless of how much energy customers consume. Because production plant capacity is required to meet peak demand requirements, plant capacity costs are appropriately allocated to customers based on their contribution to peak demands, since there is a direct relationship to the demand that customers place on the system.

The record further shows that the various alternative demand allocation methodologies proposed by the OUCC, IG, Joint Municipal Group, and South Bend are not consistent with the Company's load profile during the Test Year and should not be accepted. More specifically, the evidence shows I&M Indiana has historically been a two-seasonal peaking utility and that I&M's 2018-2019 IRP shows this profile is expected to continue through 2038. Spaeth Rebuttal, 5-7; Figure MMS-R1. We conclude, based on the evidence presented, that the Company's load profile on the primary distribution system during the Test Year supports a 6 CP allocation. Considering the Company's long-standing use of a 6 CP demand allocation factor in its previously-filed rate cases, and since the Test Year load profile continues to reflect six monthly peaks, we find it appropriate to continue the 6 CP demand allocation.

(b) Transmission and Distribution Plant Allocation Methodology. The parties also disagreed over the methodology of allocating transmission and distribution plant. As discussed above, the OUCC's proposed allocation of transmission plant using a 12 CP methodology does not appropriately consider the two-seasonal peaking nature of I&M's system. Accordingly, we approve I&M's allocation methodology for transmission plant.

We also reject the IG and South Bend recommendations to change the classification of distribution plant accounts 364 through 368 to classify and allocate a portion of these accounts as customer-related. The record shows I&M's classification of distribution plant is consistent with the NARUC Manual and is based on principles of cost causation. See Spaeth Rebuttal, 13-14. Accordingly, we are persuaded that distribution plant costs included in accounts 364 through 368 are incurred based on peak demand and should be classified as demand-related and allocated using the Company's demand allocation factors. I&M's proposed classification and allocation of distribution plant continues to be an appropriate method due to its foundation in cost causation.

### C. Subsidy Reduction.

1. I&M. Mr. Nollenberger explained the revenue allocation is based on the class cost of service study performed by Mr. Spaeth. Nollenberger Direct, 6. He explained the principles and objectives underlying I&M's proposed revenue allocation among the customer classes and stated that the Company's approach reduced the current level of inter-class revenue subsidies by 25%, while also ensuring that no class received a revenue decrease based on cost of service. *Id.*, 7-8.



2. OUCC. Mr. Watkins proposed an alternative class revenue allocation methodology after considering the results of his various recommended class cost of service studies. Watkins Direct, 36-39.

3. Intervenors. Joint Municipal Group witness Mancinelli disagreed with the Company's allocation condition that ensures that no tariff class receives a decrease in total revenues and recommended that street lighting rates be lowered to cost of service because adequate street lighting is provided by local governments and provides many public benefits, with the resulting shortfall prorated across all other rate classes. Mancinelli Direct, 40-43. CAC-INCAA witness Wallach proposed to (1) maintain base revenues at current levels (*i.e.*, no increase or decrease) for those classes where the class cost of service studies show a revenue decrease at an equalized rate of return; and (2) increase base revenues for all other classes by the same percentage in order to recover any authorized revenue deficiency. Wallach Direct, 17. South Bend witness Seelye recommended that 50% of subsidies be eliminated and disagreed with the Company's proposal that no tariff class receive a decrease in total revenues. Seelye Direct, 3, 26. Auburn witness Rutter disagreed that the Company has moved all classes closer to earning the class average rate of return and recommended a rate of return for the SL class of 9.35%. Rutter, 8-10.

4. Rebuttal. In rebuttal, Mr. Nollenberger showed that I&M's revenue allocation proposal makes progress towards reducing current inter-class subsidies, consistent with all parties' general interests. Nollenberger Rebuttal, 5-6. With respect to Mr. Seelye's recommendations, Mr. Nollenberger stated that while other customer classes are experiencing an average total revenue increase of more than 11%, it is reasonable to expect that no rate class receive a rate reduction. He added I&M's approach strikes a reasonable balance between reducing current subsidies and managing class impacts as compared to South Bend's proposal. *Id.* at 7. He explained Mr. Wallach's approach would make uneven progress towards mitigating the current level of inter-class subsidies. Nollenberger Rebuttal, 8.

5. Discussion and Finding. We find I&M's proposed method of distributing its requested rate increase in a manner to reduce current interclass subsidies by 25%, however, we agree with Mr. Mancinelli that Street Lighting service provides an important public safety benefit. Therefore, we order that Street Lighting service have a 29.2% rate reduction, consistent with I&M's cost of service results. Nollenberger Direct, Att. MWN2 at 4. while also ensuring that no class received a revenue decrease based on cost of service The remainder of the subsidy reductions proposed by I&M, —isare a reasonable step toward cost-based rates and strikes the appropriate balance between progress toward eliminating interclass subsidies and a recognition of the rate impacts on the various tariff classes. Therefore, subject to our findings in Sections 15.A.4.(d) and 16.B.3. below, we approve Petitioner's proposal.

15. Rate Design. Mr. Nollenberger presented the rate design supporting I&M's proposed tariffs and explained in general, the Company's approach is to design rates and rate components that reflect the underlying costs of the Company. Nollenberger Direct, 9. He said this includes collecting fixed costs through fixed and/or demand charges and variable costs through energy charges whenever practical. *Id.* He also discussed rate design changes proposed for certain of I&M's riders. *Id.*, 28-30. Based on the record presented, we find the Company's



undisputed rate design proposals to be reasonable and should be approved. The disputed rate design issues are discussed below.

**A. Commercial and Industrial Rates.**

**1. Tariffs R.S.–PEV and G.S.–PEV.**

(a) I&M. Mr. Cooper testified Tariffs R.S.–PEV and G.S.–PEV are being proposed as part of a comprehensive package of tariffs, rebates, and incentives to attract residential, commercial, and industrial customers to the electric vehicle market. Cooper Direct, 16. Both tariffs are designed to encourage customers to charge plug-in electric vehicles (“PEVs”) during off-peak hours.

(b) OUCC. Ms. Aguilar recommended I&M’s PEV Pilot include higher rates for charging during on-peak hours to disincent individual customers from charging during peak times. Aguilar, 20.

(c) South Bend. South Bend witness Seelye said the off-peak energy charge should be lowered to reflect cost of service and to encourage greater utilization of the service. Seelye, 5, 43-46. He further stated there is no basis for prohibiting net metering customers from taking service under Tariff G.S.-PEV and the exclusion is unduly discriminatory. Seelye, 5, 46.

(d) Rebuttal. Mr. Lehman disagreed with Ms. Aguilar that a punitive approach is necessary to accomplish off-peak PEV charging. Lehman Rebuttal, 6. He stated I&M’s proposal is designed to maximize enrollment of eligible participants and shift their PEV charging load to off-peak hours. He also disagreed with Mr. Seelye’s recommendation to lower the off-peak charging rate and noted Mr. Seelye’s proposal would result in no incremental contribution to fixed costs from participants’ off-peak PEV charging, and thus no corresponding benefit to all other customers. Lehman Rebuttal, 11.

(e) Discussion and Finding. The record shows the alternative rate designs proposed by the OUCC and South Bend would serve to discourage enrollment (in the case of the OUCC) and eliminate the incremental contribution to fixed costs from participants (in the case of South Bend). In contrast, we find I&M’s proposed Tariffs R.S.–PEV and G.S.–PEV are reasonably designed to encourage off-peak charging behavior while ensuring all other non-participating customers also benefit from this activity. The record further shows that South Bend’s recommendation to allow participation by distributed generation customers is incompatible with the per-kWh credit design of the tariff and impractical from a billing standpoint. Lehman Rebuttal, 9. Accordingly, we approve Tariffs R.S.–PEV and G.S.–PEV as proposed by I&M.

**2. Tariff IP.**

(a) Walmart. Walmart witness Chriss recommended: 1) any approved revenue increase to the IP class be applied to each service level’s demand charge; 2) maintain the first block energy charges at current levels; and 3) reduce the second block energy charges as proposed by I&M. Chriss, 31-32.

(b) Rebuttal. Mr. Nollenberger provided a comparison of estimated total bill impacts between the Company's and Walmart's recommended Tariff IP rate design. Nollenberger Rebuttal, 17; Attachment MWN-R3. He continued to support I&M's proposed Tariff IP rate design, but said Walmart's proposed Tariff IP rate design was not unreasonable.

(c) Discussion and Finding. The record shows Walmart's proposed rate design focuses on a specific rate component rather than a uniform change in all Tariff IP rate components, excluding customer charges. Nollenberger Rebuttal, 17. We find I&M's proposed Tariff IP rate design to be reasonable and therefore is approved.

### 3. Tariff LGS.

(a) Intervenors. Kroger witness Bieber stated I&M's LGS rate design significantly understates demand-related charges while overstating energy charges relative to the underlying cost components. Bieber Direct, 4. He recommended a rate design that would increase demand-related charges to 65% of the demand-related costs while reducing the energy charges by a corresponding amount to recover I&M's total proposed LGS revenues. Bieber Direct, 4, 6-17.

Walmart witness Chriss recommended collecting a greater percentage of the LGS revenue requirement through the demand charge. More specifically, he recommended: 1) any approved revenue increase to the LGS class be applied to each service level's demand charge; 2) maintain the first block energy charges at current levels; and 3) reduce the second block energy charges as proposed by I&M and increase the demand charge to account for the reduced second block energy charge revenues. Chriss at 21-30.

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

(c) Discussion and Finding. I&M's proposed Tariff LGS reasonably reflects cost causation and other rate design principles such as gradualism. Mr. Bieber and Mr. Chriss recommended Rate LGS be designed to better meet their respective company needs. We find that I&M's proposal more equitably distributes the rate increase among lower and higher load factor LGS customers and results in rate continuity for customers as usage changes. Therefore, we approve I&M's proposed Tariff LGS rate design.

### 4. Tariffs Water and Sewage Service (WSS) and Municipal Service (MS).

(a) I&M. Mr. Nollenberger explained the proposed changes to tariff classes MS and WSS, which align with the Company's general rate design objective of recovering proportional amounts of fixed costs through fixed and/or demand charges. Nollenberger Direct, 27-28.

(b) Intervenors. Mr. Mancinelli testified that I&M's implementation of a demand charge when demand charges presently do not apply to the class, meant that some WSS customers jump from a demand charge of zero to as high as \$11.369 per kW in a single step, contrary to the ratemaking principle of gradualism. While he agreed that adding a demand charge to the WSS rate structure incentivizes customers to improve load factors, Mr. Mancinelli reasoned that I&M's proposal is overly aggressive and unduly burdens lower load factor customers in the WSS class. Mancinelli, 50-53. He recommended that I&M's proposed WSS rate structure be modified to cap the rate impacts on low load factor customers, or alternatively, that I&M implement an hours-use rate structure for the Tariff WSS demand charge. Id. HeMr. Mancinelli testified that MS customers are also receiving significant rate increases due to the introduction of demand charges. Mancinelli, 53-54. He recommended a rate structure for Tariff MS that incorporates the demand-related rate elements of the existing Tariff GS instead of I&M's proposed Tariff MS demand charge. Mancinelli, 50-55. Mr. Seelye recommended a Tariff WSS demand charge that recovers 1) distribution demand-related costs applicable to the customer's maximum demand during any hour of the month, and 2) a demand charge that recovers production and transmission demand-related costs applicable to the customer's maximum demand during the peak hours of the month. Seelye, 41-43.

(c) Rebuttal. Mr. Nollenberger said while there is a conceptual basis for Mr. Seelye's Tariff WSS proposal, a two-part demand charge is more complex than a single demand charge. Nollenberger Rebuttal, 11. Mr. Nollenberger stated Mr. Mancinelli's Tariff MS recommendation is not an unreasonable alternative to the Company's proposed basic rate structure. However, he disagreed with implementing a flat energy charge, which would conflict with the current Tariff GS block energy charge. He said if Mr. Mancinelli's demand charge proposal is adopted, a blocked base rate energy charge comparable to Tariff GS and an energy charge for the PJM/OSS Rider should also be implemented. Nollenberger Rebuttal, 12-13.

(d) Discussion and Finding. ~~The record shows I&M's proposed Tariff WSS rate design better reflects cost causation by recovering more of the demand-related costs based on customers' actual demands than Mr. Mancinelli's proposal. Nollenberger Rebuttal, 12. The Commission agrees that the establishment of demand charges in a rate structure helps to send proper price signals to customers and incentivize efficient use of electricity. However, we are concerned that I&M's proposed WSS and MS rate structures will cause rate shock to local governments considering total demand charges in base rates and riders for WSS would go from zero to \$9.204/kW, and for MS would go from zero to \$11.556/kW. Nollenberger, WP-Att. MWN-4. Further, the record shows South Bend's proposal could require additional or alternative metering and related costs that are not reflected in I&M's Test Year forecast. Nollenberger Rebuttal, 11. Accordingly, we approve I&M's proposed rate design for Tariff WSS. Therefore, we approve Mr. Mancinelli's proposed Hours/Use rate structure for Rates WSS and MS, with the changes to that proposal recommended by Mr. Nollenberger to include a blocked base rate energy charge comparable to Tariff GS and an energy charge for the PJM/OSS Rider.~~

## **B. Residential Rates.**

1. I&M. Mr. Nollenberger testified I&M proposes two primary changes to its standard residential rate design. First, he said I&M proposes to increase the monthly service charge from \$10.50 per month to \$15.00 per month. Second, he said I&M is proposing a declining-block volumetric energy rate structure, where energy usage above 900 kWh is charged at a lower cents-per-kWh rate. Nollenberger Direct, 15. Mr. Nollenberger stated I&M is also proposing a new optional residential rate schedule (Tariff RSD) that will be available for up to 4,000 customers. Nollenberger Direct, 25. He said Tariff RSD uses a three-part rate structure which includes a monthly service charge, a kWh energy charge, and an on-peak kW demand charge. Nollenberger Direct, 25-26. He discussed the benefits of this pilot tariff and described how the Company designed the proposed Tariff RSD rates. Nollenberger Direct, 26-27.

2. OUCC. Mr. Watkins recommended no change in I&M's monthly residential service charge. He also recommended I&M maintain a flat volumetric energy rate per kWh of usage and compared I&M's proposal to FERC's adoption of a straight-fixed variable ("SFV") pricing method. Watkins Direct, 44. He argued the proposed customer charge and implementation of a declining-block energy rate would promote additional consumption and would stifle customers' abilities to manage their electric bills. Watkins Direct, 48. Mr. Watkins did not oppose the pilot Tariff RSD, but did recommend several administrative and reporting requirements as part of the pilot program. Watkins Direct, 48-49.

3. CAC-INCAA. Mr. Wallach recommended a monthly residential service charge of \$10.12 per bill. Wallach Direct, 42-43. He further recommended the Commission reject I&M's proposed declining-block rate structure. With respect to I&M's proposed Tariff RSD, Mr. Wallach expressed concern that the demand charge would dampen signals for conservation and encourage inefficient customer behavior. *Id.*, 43.

4. Rebuttal. In rebuttal, Mr. Nollenberger testified the OUCC and CAC-INCAA recommendations would not provide efficient price signals because they would overstate the variable cost associated with the incremental consumption or conservation of electricity. Nollenberger Rebuttal, 22-23. He explained I&M's proposal to recover a portion of fixed, demand-related distribution costs through a declining block energy rate structure is more cost-justified than one that collects demand-related costs through a flat volumetric energy charge. Nollenberger Rebuttal, 24. He explained I&M's rate design will still recover close to 90% of total residential costs through the volumetric energy charge and thus is not a "high" customer charge or a straight-fixed variable rate structure. Nollenberger Rebuttal, 27-28. Mr. Burnett explained the OUCC and CAC-INCAA's assertions rest on a hypothetical that does not reflect what is actually being proposed in this case. Burnett Rebuttal, 15-17. He testified actual experience following I&M's last rate case demonstrates that increasing the fixed customer charge did not lead to an increase in residential usage. Burnett Rebuttal, 17-19.

Mr. Nollenberger explained Tariff RSD can actually encourage more efficient customer behavior by providing a volumetric rate that more closely aligns with the true variable cost of energy. Nollenberger Rebuttal, 35. He noted this pilot tariff would also provide the customer with a third dimension to control her or his bill as opposed to a two-part rate structure. *Id.* Mr. Cooper explained implementation of Tariff RSD will be similar to that of other new tariff offerings and that I&M will provide customers with information on the tariff. Cooper Rebuttal,

7. He stated the OUCC has not shown why its proposed reporting and recordkeeping requirements related to the pilot are reasonable nor shown that any potential benefits would be greater than the associated administrative costs. *Id.*

5. Discussion and Finding.

(a) Residential Customer Charge and Declining Block Rates.

The OUCC and CAC-INCAA opposition to I&M's customer charge and declining block rate proposal focused on whether I&M's proposed rate design would send inefficient price signals. We begin our discussion by noting that I&M has not proposed SFV rates. In Cause No. 44576, we approved an increase to IPL's customer charge and the continuation of a declining-block rate structure. *Re IPL*, Cause No. 44576, p. 72, 2016 WL 1118795, 329 P.U.R.4th 486 (IURC 3/16/2016). In that case, the Commission found IPL's proposal was "demonstrably short of SFV rates." The same is true here – I&M's rate design proposal will still recover close to 90% of total residential costs through the volumetric energy charge. Nollenberger Rebuttal, 27-28. There is no evidence that the customer charge as designed even reaches the level of full distribution system fixed cost recovery. Moreover, the record shows residential usage did not increase following the rate design changes approved in I&M's last rate case, contrary to the OUCC and CAC-INCAA assertions. Burnett Rebuttal, 17-18. 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. We find that the increase in customer charge is reasonable and consistent with the Commission's preference for gradual changes in rate structures.

With respect to I&M's declining-block rate structure, the record shows I&M's proposal is more cost-justified than one that collects demand-related costs through a flat volumetric energy charge. Nollenberger Rebuttal, 24. We note that in Cause No. 44576, we found that replacing declining block energy rates with inclining block rates could result in harm to customers that use an above average amount of energy. *Re Indianapolis Power & Light Co.*, Cause No. 44576, Order at 72 (IURC 3/16/2016). Here, the Company's proposal to recover all customer-related costs, plus the total secondary distribution costs, through the combination of the monthly service charge and first block volumetric energy charge is a reasonable step towards a better alignment between the collection of these costs with the local, fixed nature of those costs.

Ultimately, we find that Petitioner's proposed rate design to increase the customer charge and implement declining block rates should be approved. We further find that this structure does not violate principles of gradualism, because gradualism "is best considered in the context of the entire customer bill and not discrete charges within the bill." *IPL*, Cause No. 44576, p. 72.

(b) Optional Residential Demand Metered Tariff. No party directly objected to I&M's proposed Tariff RSD. We find I&M's proposal will provide a tariff option that better aligns customers' rates with the types of costs being recovered, which will provide improved price signals as opposed to one that recovers demand-related costs through volumetric energy charges. The record shows Tariff RSD will also help customers control their bills by managing their peak demand. Accordingly, we find Tariff RSD is reasonable and should be approved. I&M explained that implementation of this tariff will be similar to that of other new tariff offerings and that I&M would provide customers with information on the tariff and how to



best utilize their electric service to provide a least cost, efficient solution to their specific energy needs. With respect to the OUCC and CAC-INCAA's recommended reporting requirements, we find such requirements to be unnecessary at this time, particularly since reporting on individual customer behavior might deter customers from participating in the pilot.

C. **Riders.** I&M proposes to retain all existing rate adjustment mechanisms, with certain modifications, and to add one new mechanism – the AMI Rider. We find the unopposed continuation of, and modifications to, I&M's riders to be reasonable and we find they should be approved. We discuss the contested issues below.

1. **AMI Rider.**

(a) **I&M.** Mr. Williamson testified I&M is proposing the AMI Rider to track the full costs associated with I&M's AMI deployment until the deployment is completed and the associated costs are reflected in base rates. Williamson Direct, 37. He identified the costs I&M proposed to track incremental to the level included in base rates and explained how the AMI Rider will be implemented and the necessary deferred accounting authority. *Id.*, 37-39.

(b) **OUCC.** Mr. Blakley testified that if the AMI Rider is accepted, then the retirement of the AMR meters should be recognized as a decrease in depreciation expense in the new rider. Blakley, 1, 9-11, 15.

(c) **Intervenors.** Kroger witness Bieber opposed the AMI Rider as single-issue ratemaking and said it does not meet the criteria for this type of regulatory treatment. Bieber, 5, 23-24. Joint Municipal Group witness Cannady also opposed the AMI Rider to reconcile estimated AMI costs and said if AMI deployment is approved, the Commission can conduct a prudence review of the costs in I&M's next rate case. Cannady, 4, 32, 36. Auburn witness Rutter recommended the Commission disallow both recovery of and return on the undepreciated book value of the presently in service AMR meters once they are retired and replaced by AMI meters. Rutter, 6.

(d) **Rebuttal.** Mr. Williamson stated the OUCC's recommendation that the reduction in depreciation expense associated with retired AMR meters be reflected as a reduction to the AMI Rider revenue requirement is consistent with the Company's intent and proposal. Williamson Rebuttal, 26. With respect to the intervenors' testimony, Mr. Williamson explained why the Company's proposed AMI Rider is a better option for I&M's customers. Williamson Rebuttal, 26-27. He said Mr. Rutter's recommendation is troubling in many ways and should not be adopted by the Commission as it would depart from proper accounting and ratemaking for the remaining book value of retired property. *Id.*, 27-30.

(e) **Discussion and Finding.** As discussed above, we have approved ~~deferred accounting of the AMI project costs until the next base rate case. the proactive, planned AMI deployment proposed by I&M. Given the efficiency associated with incurring this significant investment over a relatively short period of time we find I&M's proposal to recover the costs of the AMI deployment through the AMI Rider is reasonable. This approach better reflects the cost of providing service to customers over time, avoids~~



~~compounding the costs onto future customers, and allows the Company to provide updates to the Commission and I&M's stakeholders on the progress of this deployment. Williamson Rebuttal, 26-27. With respect to Mr. Rutter's recommendation, we find Mr. Rutter identified no valid reason for the Commission to depart from established practice and further find his approach would discourage prudent, proactive replacement of assets. To avoid single-issue ratemaking, the Commission approves riders when they are generally outside of the utility's control and highly variable. Neither is the case with costs related to AMI deployment. AMI deployment is no different than any other transmission and distribution system improvement. Had I&M presented its AMI plan as part of a TDSIC case, we could have considered whether it was appropriate to allow recovery of AMI costs in between rate cases under IC 8-1-39-2, but that is not how this case was presented. Accordingly, we do not approve the proposed AMI Rider and will review the deferred accounting of AMI project costs in the next base rate case, and associated deferred accounting authority as proposed by I&M.~~

2. Environmental Cost Recovery ("ECR") Rider.

(a) I&M. Mr. Williamson proposed the ECR be used to track the consumables and net allowances costs I&M incurs in operating its generating assets for the benefit of its customers. Specifically, he proposed to embed the forecasted Test Year level of consumables and allowances costs in base rates of \$21,785,467 (Total Company) and track any annual over/under variances in the ECR from the embedded level in base rates.

(b) OUCC. Ms. Aguilar opposed tracking environmental consumables and emission allowances above or below the embedded base rate amount, stating such amounts are not variable and not expected to increase over the next few years. Aguilar, 14-15, 28. Mr. Blakley opposed tracking expenses related to capital projects that have been embedded in base rates. Blakley, 1, 3-6, 14.

(c) ICC. ICC witness Medine stated that should the Commission approved I&M's request for recovery of costs in the ECR, I&M should not include the costs recovered in base rates in its Rockport wholesale market offer price. Medine, 5, 17.

(d) Rebuttal. Messrs. Williamson and Kerns responded to the OUCC and ICC contentions and identified the numerous factors contributing to the uncertainty and volatility around future consumables and allowances costs. Williamson Rebuttal, 19-21; Kerns Rebuttal, 2-5. Mr. Kerns also responded to Ms. Medine's testimony and said I&M's PJM offer prices for Rockport in the wholesale power market should not be a basis for determining whether a cost reasonably and necessarily incurred to provide retail service is tracked or not through the prices I&M charges for retail services. Kerns Rebuttal, 5. He said the Commission should not pre-define how I&M offers its power into PJM as doing so could increase the cost of generation for I&M's customers by eliminating I&M's ability to manage costs. Kerns Rebuttal, 5.

(e) Discussion and Finding. The record shows consumables and allowances expenses are much like fuel costs in that they vary considerably based on how much the Rockport Units operate. Kerns Direct, 25-26; Williamson Direct, 44. While the OUCC challenged the variability of these costs, the evidence shows consumables expenses have varied

historically, are projected to continue to vary significantly (both up and down) over time, and that the primary drivers are PJM market prices and the fuel mixture. Kerns Rebuttal, 3-4. With respect to allowances costs, the record shows I&M has been able to reduce allowance costs to the benefit of customers but volatility remains. New environmental regulations or restrictions can be introduced at any time, resulting in changes that are outside the control of I&M. Other factors largely outside the control of the Company can also impact market energy prices and the dispatch of the Rockport Units, resulting in changes to both consumables and allowances expenses. Williamson Rebuttal, 19. The Company's proposal will ensure that customer rates ultimately reflect only the actual cost of consumables and allowances costs incurred to provide them service. With respect to the ICC's recommendation, we find I&M's PJM offer prices for Rockport in the wholesale power market should not be a basis for determining whether or not a cost reasonably and necessarily incurred to provide retail service is tracked through the prices I&M charges for retail services. Furthermore, the Commission declines to pre-define how I&M offers its power into PJM as doing so could increase the cost of generation for I&M's customers by eliminating I&M's ability to manage costs. Accordingly, we approve I&M's proposed changes to the ECR.

### 3. Fuel Adjustment Clause ("FAC").

(a) I&M. Ms. Heimberger sponsored I&M's projected Test Year FAC basing point of 12.989 mills per kWh. Heimberger Direct, 27; Attachment NAH-8. Mr. Williamson said the Company is requesting the Commission waive the purchased power benchmark procedures as applied to I&M in Cause No. 43306, both for this case and all future proceedings. He explained circumstances today render it unnecessary for this issue to be revisited in each general rate case. Williamson Direct, 46. He said I&M also proposes to continue crediting customers for revenues associated with participation in I&M's voluntary renewable programs. *Id.*, 7.

(b) OUCC. Mr. Eckert accepted I&M's recommended base cost of fuel and request for a permanent waiver of the purchased power benchmark. He said should the Commission continue to allow I&M to include renewable energy certificate ("REC") revenues in its FAC filings, it should be contingent on I&M's agreement to allow the OUCC a minimum of 35 days to review I&M's FAC proceedings. Eckert, 18-20.

(c) Rebuttal. Mr. Williamson said the calculation for the sale of RECs is a very simplistic calculation that does not justify the need for additional days to review the FAC filing.

(d) Discussion and Finding. The record shows I&M's proposed base cost of fuel of 12.989 mills per kWh is unopposed and should be approved. Similarly, no party opposed I&M's request for a permanent waiver of the purchased power benchmark. The record shows the factors that led to the development of the benchmark conditions adopted in Cause No. 43306 have been heavily mitigated and a permanent waiver is reasonable. Finally, we note the deadline for the OUCC to file its FAC report is set by statute. Ind. Code § 8-1-2-42(b). The record shows the inclusion of REC sales in the FAC proceeding is a simplistic calculation that has a minimal impact on the FAC filing. Williamson Rebuttal, 67. The OUCC continues to perform an interim audit that reviews, to a large degree, the first three months of the semi-annual

FAC period. I&M has committed to continuing to provide the OUCC and its consultant an audit package immediately following the filing of the FAC to expedite and facilitate the review process. Williamson Rebuttal, 67. Accordingly, we find the OUCC presented no compelling reason to deviate from the statutory FAC filing process and reject their proposal.

4. IM Green Rider.

(a) I&M. Mr. Lucas explained I&M proposes to consolidate its Green Power Rider (“GPR”) and Renewable Energy Option (“REO”) into a single revised voluntary renewable program called *IM Green* that will offer customers the ability to purchase renewable energy through a combination of wind and solar RECs. Lucas Direct, 35. He discussed the program design and explained the *IM Green* program will allow all customers to purchase RECs as a percentage of their monthly kWh usage. *Id.*, 35. He said large commercial and industrial customers can participate under the basic terms of the *IM Green* program or through a second option which will allow eligible commercial and industrial customers to participate through a written services agreement tailored to their specific business objectives and renewable energy needs. *Id.* Mr. Lucas described how the proposed *IM Green* program will benefit participating and non-participating customers. *Id.*, 37-38. Mr. Cooper discussed the use of the S&P Global Energy Credit Index for the New Jersey Class 1 RECs to calculate the market rate for RECs under the *IM Green* program and discussed I&M’s proposed treatment of RECs purchased by customers. Cooper Direct, 17-19.

(b) OUCC. Ms. Aguilar supported consolidating the GPR and REO into the single *IM Green* Rider. Aguilar, 6-7. However, she recommended I&M monetize unsubscribed RECs and pass the proceeds onto ratepayers through the FAC for the benefit of all ratepayers. *Id.*, 13.

(c) Intervenors. IG witness Dauphinais recommended I&M work with its large customers to provide expanded options for those customers. Dauphinais, 3, 32-33. Walmart witness Chriss recommended approval of I&M’s Custom Agreement option and proposed alternative language related to REC pricing. Chriss, 6-7, 35-37.

(d) Rebuttal. Mr. Lucas said the OUCC recommendation to monetize unsubscribed RECs would not be in the best interest of I&M’s customers and is at odds with the OUCC’s general support for renewable, green energy. Lucas Rebuttal, 27-29. He said I&M would be interested in engaging with Walmart to explore potential utility partnership opportunities and explained the New Jersey REC price provides a reasonable market-based index to value RECs absent a market in Indiana. *Id.*, 29-30.

(e) Discussion and Finding. The record shows I&M’s proposal to consolidate the GPR and REO programs into the single *IM Green* program is reasonable, provides opportunities for all of I&M’s customers to participate, and provides I&M flexibility to tailor its offerings to meet the specific interests and needs of its customers. Lucas Direct, 35-36; Cooper Direct, 17-18. While the OUCC recommended I&M be required to monetize all of its unsubscribed RECs, the record shows this requirement would prevent I&M and its customers from claiming that a part of their generation came from carbon free energy sources and is contrary to the expressed interest from I&M’s customers that I&M provide energy from

renewable resources. Lucas Rebuttal, 28. With respect to Mr. Chriss' concern regarding the price index used in the *IM Green* program, the record shows there is a distinction between New Jersey Class 1 RECs (which trade in the \$6-\$7 range) and New Jersey Solar RECs (which trade in the \$200-\$230 range). Tr., I-40. We find the use of the S&P Global Renewable Energy Credit Index for New Jersey Class 1 RECs is a reasonable proxy for Indiana RECs and provides a relatively stable price index. Cooper Direct, 17-18. We further find I&M's proposal to allow for custom written agreements with its large commercial and industrial customers under the *IM Green* to be reasonable. No party opposed having this option, and the record shows it will allow larger customers and I&M flexibility in customizing an offering specific to the customers' needs. *Id.*, 18. Accordingly, we find the *IM Green* Rider should be approved as proposed by I&M.

#### 5. Off-System Sales Margin Sharing.

(a) I&M. I&M proposes to continue sharing of off-system sales ("OSS") margins on a 95/5 basis, meaning that 95% goes to customers and 5% goes to the Company, with zero embedded in base rates. Williamson Direct, 7-8; 48-49. Mr. Williamson said continuing to share OSS margins is reasonable because it provides an incentive for the Company to maximize the benefits of OSS for both the Company and its customers. *Id.*, 49. In addition, he said continued sharing recognizes the value of I&M's Commercial Operations organization, which is responsible for the PJM market bidding and hedging strategy for I&M's generation fleet, providing substantial value to I&M and its customers by optimizing I&M's OSS margins. *Id.*, 49-50. Mr. Williamson explained it is both reasonable and necessary to track OSS margins from \$0 (rather than embed a certain level in base rates) as OSS margins are largely contingent on PJM market energy prices which are variable due to a number of factors outside the control of the Company and in total OSS margins are significant and can vary significantly from year to year. *Id.*, 50; Figure AJW-5.

(b) OUCC. Mr. Lantrip recommended continued tracking of OSS margins, but with 100% of all OSS margins greater than zero dollars allocated to ratepayers. Lantrip, 1, 5-8, 13.

(c) Intervenors. The Industrial Group and Joint Municipal Group both proposed that 100% of OSS margins above zero be allocated to I&M's customers. Dauphinais, 3, 30-31, 33; Mancinelli, 3-4, 298-30, 59. [Mr. Mancinelli testified that I&M's customers should receive 100% of OSS margins for three reasons: \(1\) cost responsibility for generation is fully borne by retail customers; \(2\) I&M is already fairly compensated through allowed return on its generation investment; and \(3\) OSS provides other benefits to the company such as efficient use of generation assets.](#) Kroger recommended the Commission order I&M to include \$38.4 million in base rates and allow 95/5 sharing of the incremental OSS margins above or below that amount. Bieber, 5-6, 26. Mr. Bieber stated if the Commission embeds zero dollars in base rates, then customers should receive 100% of the OSS margins.

(d) Rebuttal. Mr. Williamson said I&M's proposal is a very modest and reasonable request that provides a small yet meaningful share to I&M to further incentivize optimizing OSS margin to reduce the cost of providing service to all customers. Williamson Rebuttal, 23-25. He testified completely eliminating this incentive will not properly compensate I&M for its efforts to effectively compete in the market and the risks it is taking to

create the value being shared with customers. *Id.*, 23. He objected to Kroger's alternative proposal, stating embedding such a high level of OSS margins shifts a significant amount of risk to the Company's shareholders in exchange for a very small potential benefit of retaining 5% if annual OSS margins exceed the Test Year level. Williamson Rebuttal, 25-26.

(e) Discussion and Finding. I&M proposes to continue its existing OSS margin sharing mechanism. The OUCC and intervenors proposes to change the current mechanism so as to provide 100% of OSS margins to customers. Given our decision that I&M's failure to account for stranded costs in its wholesale contracts with IMMIDA was imprudent, we think it inappropriate to allow I&M to benefit from that imprudence by retaining any part of the OSS margins, which will increase due to the lost IMMIDA load. We conclude that a continued sharing of OSS margins is warranted and appropriate in light of the actions I&M undertakes to maximize OSS margins for the benefit of I&M and its customers. I&M's response to the Commission's docket entry further elaborated on how I&M's expertise in the wholesale energy market creates value for I&M and its customers and identified the risks I&M is taking to create the value being shared with customers. Pet. Ex. 43 (I&M Response to Commission Docket Entry), 17-20. These risks include the variable cost of generation, credit risk, counterparty performance risk, volumetric risk, and basis risk. We find continuing the existing OSS margin sharing structure provides an incentive for the Company to maximize the benefits of OSS for both the Company and its customers. Therefore, the Commission finds that customers should receive 100% of OSS margins. With respect to Kroger's proposal to embed \$38.4 million in base rates, we find embedding zero dollars is more appropriate because it avoids artificially reducing I&M's revenue requirement. If an amount is embedded in basic rates, a decline in OSS margins going forward could dramatically reduce the Company's operating income. Pet. Ex. 43, 21-23. We find sharing from dollar zero avoids this result and avoids making the Company's authorized return on retail service unreasonably dependent on the competitive wholesale market. Accordingly, we approve I&M's proposal to embed zero dollars of OSS margin in base rates, with 95/5 (customer/Company) sharing of 100% of OSS margins above zero credited to customers through the OSS/PJM Rider.

#### 6. PJM Rider and PJM Capacity Performance Insurance.

(a) I&M. IG witness Dauphinais and Kroger witness Bieber opposed NITS tracking and said the costs are largely under the control of the Company and not volatile or variable in a manner that warrants a tracker. Dauphinais, 2, 9-30, 33; Bieber, 5, 20-21. Ms. Cannady recommended disallowing recovery of the insurance premiums because ratepayers should not be responsible for covering the cost of insuring a risk of non-performance under the PJM rules without detailed information on the likelihood of non-performance, and whether such non-performance was outside the Company's control I&M has not shown the expense provides a benefit to customers at this time. Cannady, 4, 335. In addition, Ms. Cannady noted that under the PJM Capacity Performance Rules, it is possible for I&M to actually receive compensation for the non-performance of other members of PJM. Id. At 34-35. Mr. Bieber testified I&M earns a rate of return on its production plant which is intended to provide an appropriate balance between the risks and rewards for I&M's operations. He said if I&M elects to purchase insurance to mitigate its operational risk, that cost should not be passed on to customers. Bieber, 5.



Mr. Ali described I&M's role as a Generator, Load Serving Entity, and Transmission Owner ("TO") in PJM and the various charges and credits that the Company experiences resulting from each role. Ali Direct, 7-9. He explained NITS charges represent the cost for I&M and other PJM network customers to integrate, economically dispatch, and regulate their current and planned network resources to service their network load. *Id.*, 9. He discussed the transmission planning process and the forecast of PJM revenues and charges. *Id.*, 9-19. He said the costs to be recovered through the OSS/PJM Rider are significant and the NITS costs in particular are expected to increase. *Id.*, 19-20. He explained NITS costs are potentially variable or volatile and are largely outside of I&M's control. *Id.*, 20-21. He said continued recovery of NITS costs through the OSS/PJM Rider remains a reasonable process. *Id.*, 21-22.

(b) OUCC. Mr. Gahimer contended the AEP Transmission Agreement and creation of I&M Transco ceded I&M's control of its NITS charges to other AEP affiliates and therefore the proposal to continue to track NITS charges should be denied. Gahimer, 6-7, 20. More specifically, he noted that in I&M's service territory, transmission is owned by I&M itself and I&M Transco. Gahimer, 6. He said through the AEP Transmission Agreement, each of the AEP Operating Companies providing utility service in PJM's footprint pays a share of the NITS costs associated with every Attachment H-14 and H-20 transmission facility in the PJM AEP East footprint, not just those projects it owns or even those in its own service territory. *Id.*, 6-7. He said by shifting some of I&M's transmission costs to other AEP utilities, the AEP Transmission Agreement effectively cedes some of the other AEP utilities' control to I&M while ceding some of I&M's control to them. *Id.*, 7. Mr. Gahimer proposed the estimated Test Year level of NITS charges be included in base rates, subject to a compliance filing through which base rates are adjusted downward if I&M's actual NITS charges are lower than the estimated level. Gahimer, 27. Mr. Gahimer stated the PJM Capacity Performance insurance cost is discretionary, not required, and should not be recovered from ratepayers. Gahimer, 22-27. Mr. Lantrip testified continued tracking of non-NITS costs seems appropriate at this time, as well the Company's proposal to embed forecasted Test Year level of all non-NITS costs in base rates. Lantrip, 8, 13-14.

(c) Intervenors. IG witness Dauphinais and Kroger witness Bieber opposed NITS tracking and said the costs are largely under the control of the Company and not volatile or variable in a manner that warrants a tracker. Dauphinais, 2, 9-30, 33; Bieber, 5, 20-21. Ms. Cannady recommended disallowing recovery of the insurance premiums because I&M has not shown the expense provides a benefit to customers at this time. Cannady, 4, 35. Mr. Bieber testified I&M earns a rate of return on its production plant which is intended to provide an appropriate balance between the risks and rewards for I&M's operations. He said if I&M elects to purchase insurance to mitigate its operational risk, that cost should not be passed on to customers. Bieber, 5.

(d) Rebuttal. Mr. Williamson said a review of the historical and future trend demonstrates from year to year NITS costs are subject to change. Williamson Rebuttal, 7. He said NITS costs are rising such that it is not possible to set a test year level in base rates that is reasonably representative of ongoing NITS costs. He disagreed tracking PJM costs reduces or eliminates the Company's incentive to reduce costs, noting the impact of the increasing NITS cost is so large it cannot be reasonably managed by offsetting costs elsewhere. *Id.*, 13. Mr. Williamson reiterated that PJM NITS charges are expected to increase significantly



the year following the Test Year and showed that if I&M does not continue to track PJM NITS as proposed by the Company, it would decrease I&M's earned ROE by approximately 1.90% in the first calendar year following this rate case, making I&M's earned ROE less than that recommended by any intervenor in this case. Williamson Rebuttal, 12. He said it is undoubtedly clear that not tracking PJM NITS would eliminate any reasonable opportunity I&M has to earn its authorized return.

Mr. Ali disagreed with Messrs. Dauphinais and Gahimer's contention that I&M has ceded control and said I&M does not have control over costs that other transmission owners in the AEP Zone incur, including AEP affiliates, just as other Transmission Owners and their respective state utility commissions do not have control over I&M's costs. Ali Rebuttal, 6. He explained that projects giving rise to I&M's NITS expenses are outside the control of I&M and its affiliates because Transmission Owners cannot decline to make reasonable and necessary investments in the transmission grid. He said these investments must be made to fulfill I&M's obligation to operate pursuant to Good Utility Practice and none of the transmission projects giving rise to NITS expense have been alleged to be unreasonable or unnecessary. Ali Rebuttal, 5. He said these transmission projects are driven by the underlying need for infrastructure improvements and each RTO member's respective obligation to provide safe, adequate, and reliable transmission service and facilities in accordance with the Good Utility Practice requirements that have long been the foundation for utility planning and operations and continue to be imposed on the RTO Transmission Owners by FERC. *Id.*, 6. He said ultimately, AEP's structure does not supplant the respective obligations of the RTO members to fulfill their respective public utility obligations to serve. *Id.*, 6-7. Rather, he said AEP's structure facilitates the planning process and helps AEP and I&M achieve the joint transmission system benefits the entire RTO system was created to foster. *Id.*, 7.

Mr. Ali explained the transmission projects are subject to a robust PJM and stakeholder process which provide the opportunity for stakeholders to review and provide input regarding Owner Projects. Ali Rebuttal, 7; see also Williamson Rebuttal, 13. He discussed the multiple opportunities for stakeholders to comment, provide input on additional needs, and propose alternative solutions for PJM Transmission Owners to consider. Ali Rebuttal, 8. He said I&M and AEP consider all input provided by stakeholders. *Id.* Additionally, he said I&M and AEPSC Transmission include stakeholders that are directly impacted by a given project in the project's development and prior to its submission as a Solution to PJM stakeholders to ensure that those direct impacts are considered in identifying and evaluating potential Solutions. *Id.*, 8-9. He stated I&M and AEPSC Transmission also go beyond what the M-3 Process requires by annually meeting with customers to discuss transmission needs, which provides an additional opportunity for stakeholder feedback and review of the needs of the system. *Id.*, 9. He responded to Mr. Gahimer's criticism of the FERC Formula Rate Filing process and explained the AEP Operating Companies and Transmission Companies' FERC-approved formula rates include protocols that establish an open and transparent process for any interested party to review the rates and challenge items, including the ability to challenge the prudence of actual costs and expenditures. *Id.*, 9-10. He also refuted Mr. Gahimer's suggestion that Owner Projects are less necessary than Baseline Projects, explaining the designation of a project as a Baseline or Owner Project is not indicative of the level of, or absence of, need for the project. *Id.*, 11. Instead, he said the designations simply reflect that the project addresses different system reliability and resiliency needs. *Id.* Finally, Mr. Ali responded to Mr. Dauphinais' testimony regarding non-topology

projects and explained these projects are essential to the larger projects that are submitted to and reviewed by PJM. *Id.*, 12. He explained non-topology projects are required for important operational functions such as protecting against security threats, minimizing equipment damage, reducing outage durations, and improving safety, as well as many others. *Id.*, 13. He said although these projects do not affect any load flow model used by PJM, they are still necessary for the continued safe, efficient, secure, and reliable operation of the transmission grid. *Id.*

Regarding the PJM Capacity Performance insurance, Mr. Thomas explained the question is not whether I&M is required to purchase this insurance, but whether doing so is a reasonable cost of doing business. Thomas Rebuttal, 7. He said I&M considered both the risk of an event occurring and its consequence in making the decision to purchase this insurance and that the cost of the Company's other types of insurance is recognized as a reasonable and necessary cost of service. *Id.*, 7-8. Mr. Hevert responded to Mr. Bieber's testimony and stated if Mr. Bieber's proposal were to be adopted, it would require an increase in the authorized return on equity. Hevert Rebuttal, 95-96.

(e) Discussion and Finding. No party disputes that NITS costs are significant and projected to increase; and the OUCC, Industrial Group and Kroger all recommend recovery of I&M's Test Year PJM NITS costs. Thus, the only question is whether I&M should continue to track these costs as proposed by I&M. We conclude substantial evidence supports I&M's proposal.

I&M has been and remains a member of PJM as encouraged and authorized by this Commission. *Re Commission's Investigation*, Cause Nos. 42350/42352 (IURC 9/10/2003). I&M incurs costs for transmission service provided to its customers entirely based on FERC-regulated and approved charges from PJM. The record shows I&M's membership in PJM has allowed I&M's customers to benefit from the independent regionally operated, and jointly planned and coordinated, PJM transmission grid necessary to enhance competitive wholesale markets, resource diversity and system reliability and security. Thomas Rebuttal, 4. It is reasonable that I&M recover the costs it incurs based on the PJM structure as this is the structure the Company operates under and is familiar with.

Substantial evidence shows NITS costs are variable and subject to potentially significant changes due to market and economic conditions, public policy, NERC and FERC requirements, environmental, and state regulatory requirements and other factors that can be unpredictable. Williamson Direct, 52-53; Williamson Rebuttal, 7; Ali Direct, 20; Ali Rebuttal, 4-7. The record also shows that the drivers of transmission projects are not under I&M's exclusive control, and include regulatory requirements, interconnection requests, asset performance, and the need for modernization of protection and control systems. Ali Direct, 13. While the OUCC asserted AEP's corporate structure warranted denial of I&M's request to track NITS costs, the record shows the fact that other Transmission Owners may be I&M affiliates does not change the obligation each Transmission Owner has to pursue prudent projects needed to address safety, security, efficiency as well as asset condition, performance, and risk to provide reliable services in that owner's service territory. Ali Rebuttal, 6. Moreover, the record shows that I&M's customers benefit through the coordinated efforts of the AEPSC Transmission organization that supports I&M and other affiliates and allows AEP to achieve economies of scale, maintain low costs, and provide operational expertise and efficiencies in managing the I&M transmission

system. Ali Rebuttal, 14. Accordingly we reject the OUCC contention that the AEP Transmission Agreement and the formation of I&M Transco are grounds to deny continued tracking of NITS costs.

Finally, the record shows that denial of I&M's request for continued tracking of these costs would decrease I&M's earned ROE by approximately 1.90% in the first calendar year following this rate case, making I&M's earned ROE less than that recommended by any intervenor in this case and lower than that we have found to be reasonable above. Williamson Rebuttal, 12. Accordingly, we approve I&M's request to embed the forecasted Test Year level of non-NITS PJM costs and track any annual over/under variance from the embedded level. I&M is further authorized to continue to recover 100% of NITS charges through the OSS/PJM Rider, with no amount of NITS costs embedded in base rates.

With respect to the PJM Capacity Performance Insurance premium, the record shows changes made by PJM to its capacity performance rules create the potential for I&M to be subjected to significant penalties if any of I&M's resources are experiencing an unexpected forced outage and are not available during a performance assessment interval. Thomas Rebuttal, 6. The record further shows I&M, like many other generator owners in PJM, has acquired Capacity Performance Insurance as an ordinary and reasonable expense to offset the risk of generator non-performance. *Id.* Insurance is a generally accepted means of safeguarding against loss, and the OUCC and intervenors have not shown why this particular insurance should be treated differently than the other types of insurance recognized as a reasonable and necessary cost of service. Given that the annual premium expense is a fraction of the potential Non Performance Charges (which could be in the tens of millions of dollars per event), we approve I&M's proposal to embed in base rates the annual cost of PJM Capacity Performance Insurance and track any annual over/under variance from the embedded level through the OSS/PJM Rider.

7. Resource Adequacy Rider.

(a) I&M. I&M proposes to embed in base rates its forecasted Test Year level of non-FAC purchased power costs in the amount of \$190,132,242 (Total Company), and track incremental annual costs above and below this embedded amount through the RAR. Mr. Williamson said continuing the existing structure without a "cap" or "sunset" is reasonable and ensures rates only reflect the actual cost of purchased power I&M incurs to provide service to customers. Williamson Direct, 54-55.

(b) OUCC. Mr. Lantrip did not oppose I&M's request to continue the RAR and recommended that any excess capacity sales be passed back to customers through the RAR as a means of reducing capacity purchase costs. Pub. Ex. No. 5, 2-5.

(c) Intervenors. Messrs. Dauphinais and Bieber opposed the continuation of I&M's RAR, stating these costs are predictable long-term costs that do not satisfy the criteria for tracking. Dauphinais, 3, 31-33; Bieber, 22-23. Mr. Bieber further argued that tracking these costs reduces the inherent incentive for I&M to manage its costs. Bieber, 24.

(d) Rebuttal. Mr. Williamson supported tracking both capacity purchases and sales through the RAR as proposed by the OUCC. He stated the main arguments

raised by IG and Kroger to continued tracking is in direct conflict of the point OUCC witness Lantrip makes in his testimony. Mr. Williamson said the ability to forecast significant changes in these costs on a going forward basis shows the Test Year level is not representative going forward and that tracking is appropriate. Williamson Rebuttal, 21-23. He also disagreed that tracking these costs would influence any incentive I&M has to manage the underlying costs. He said since I&M owns and leases 50% of Rockport and does not track the majority of those costs, I&M has every incentive to continue to manage the costs of Rockport regardless of whether I&M tracks the AEP Generating Company portion of these costs. *Id.*, 22.

(e) Discussion and Finding. Both I&M and the OUCC support continued tracking of purchased power costs through the RAR. While the IG and Kroger witnesses suggest these costs are not sufficiently variable to warrant tracking, the evidence presented shows these costs to be significant in amount and variable across years. Pub. Ex. No. 5, 4. The record further shows these costs are currently subject to FERC-approved and regulated purchased power contracts and are thus largely outside I&M's control. Williamson Direct, 54-55. We find continued use of the RAR will ensure rates reflect the actual cost of capacity required to comply with PJM's resource adequacy requirements and will provide benefits to customers by tracking capacity sales revenues, which serve to reduce the revenue requirement. Accordingly, we approve I&M's proposal to embed the Test Year level of non-FAC purchased power costs in base rates and track incremental annual costs above and below this amount, along with any future capacity sales revenues.

## **16. Miscellaneous Issues.**

### **A. ICC Investigation Request.**

1. ICC. ICC witness Medine contended the Fifth Modification obligation arose out of AEP's failure to timely install SCR on Rockport Unit 2 and therefore the requirements of the Fifth Modification are more akin to a fine or penalty than a regulatory requirement. Medine, 4-5, 14. She requested the Commission (1) direct I&M to investigate options for keeping Rockport Unit 2 on line past 2028 when Rockport Unit 1 is required to be closed under the Fifth Modification, (2) direct I&M to calculate the incremental costs of compliance as a result of the Fifth Modification, and (3) the Commission should determine what if any of these incremental costs should be recoverable. Medine, 5.

2. Rebuttal. Mr. Thomas said Ms. Medine's recommendations are based on her findings and statements that are simply wrong. Thomas Rebuttal, 26. He said there is absolutely no truth to Ms. Medine's assertion that "I&M admitted that the Fifth Modification to the Consent Decree was only necessary due to I&M's failure to timely install SCR on Rockport Unit 2." *Id.*, 26-27. He said the installation of the Rockport Unit 2 SCR is proceeding on track and is fully expected to be in operation by the time set forth in the Consent Decree. *Id.*, 27. He said while that deadline was extended by six months by agreement of the parties to allow negotiations to be completed, there has been no failure to timely install the Rockport Unit 2 SCR. Moreover, he said as supported by the testimony of Mr. McManus in Cause No. 43992 S1, the Consent Decree cannot be construed to be a penalty because "[t]he AEP Companies admitted no violations of law and all claims against them were released." Thomas Rebuttal, 27; Attachment TLT-1R. Mr. Thomas stated I&M leases Rockport Unit 2 and a decision to retire Rockport Unit

2 will be made by the owners of the unit, not a leasee. Thomas Rebuttal, 27. He noted the Fifth Joint Modification does provide that optionality for the owners to exercise if they choose. He testified the appropriate forum to consider the resources to serve I&M's customers is through its periodic IRP process, not a general rate case. *Id.* He explained the ICC has participated in I&M's current IRP stakeholder process and may participate going forward as there will likely be three IRPs developed before Rockport Unit 1 will retire. He concluded there is no need for the Commission to order an investigation as part of this proceeding. *Id.*

3. Discussion and Finding. The record shows the ICC's request that I&M investigation options for keeping Rockport Unit 2 on line past 2028 is based on a faulty premise. More specifically, the record shows decisions about the continued operation of Rockport Unit 2 will be made by the owners of the unit, not I&M. Thomas Rebuttal, 27. Further, Ms. Medine's assertions that I&M failed to timely install the Rockport Unit 2 SCR and that costs related to the Fifth Modification "are akin to a fine for failure to perform, not a regulatory requirement" are not substantiated by the evidence presented. More specifically, the record shows the installation of the Rockport Unit 2 SCR is proceeding on track and is expected to be in operation by the time set forth in the Consent Decree. Thomas Rebuttal, 27. In other words, there has been no failure to timely install the Rockport Unit 2 SCR as Ms. Medine contends. Similarly, Ms. Medine's claim that the requirements of the Fifth Modification are a "penalty" is contradicted by the plain language of the Consent Decree, which states it is being entered into "without any admission by Defendants, and without adjudication of the violations alleged in the complaints or the [Notices of Violations]". I&M Admin. Notice 3 (AEP Consent Decree), p. 8 of 121; see also Thomas Rebuttal, 27; Attachment TLT-1R at 4 (explaining the AEP Companies "admitted no violations of law and all claims against them were released"). Finally, the issue Ms. Medine raises relates to I&M's resource planning and we agree with I&M that the appropriate forum to address consider the resources to serve I&M's customers is through its periodic IRP process, not this general rate case. Thomas Rebuttal, 27. Accordingly, ICC's request is denied.

## **B. Streetlighting.**

1. South Bend. South Bend witness Dorau stated I&M's rates for LED streetlighting conversions are overstated and unreasonable. Dorau, 19. She said streetlights are an essential public service which promotes public safety and economic development. *Id.*, 20. However, she said every street light fixture installed by I&M at South Bend's request, while adding to safety and quality of life in neighborhoods, is also a permanent increase to South Bend's ongoing operational costs, energy use, and carbon footprint. *Id.* Mr. Seelye testified I&M is proposing streetlighting rates that are excessive. Seelye, 4, 35-37. He said there appears to be an error in the development of I&M's proposed streetlighting rates in that while SL rates were supposed to be allocated a zero increase in revenue, Mr. Nollenberger's workpapers show I&M is proposing to increase the rates of each type of light by 4.37% to 5.14%. *Id.*, 33. He added that because I&M is proposing to reduce its fuel basing point, I&M's lighting rates should also be going down, not up. *Id.*, 33-35. Mr. Seelye also asserted there were flaws in I&M's Public Efficient Streetlight ("PES") program because it fails to capture the significant O&M savings resulting from the replacement of LED lights. *Id.*, 37-40. He also presented revised lighting rates for Tariffs ECLS and SLS. *Id.*, 40-41; Attachment WSS-11.

Mr. Sommer testified I&M should be ordered to revise its LED streetlighting rates to reflect a lower level of maintenance costs and longer fixture lives. Sommer, 5, 12-17. He said I&M should also be required to commit to working with interested municipalities to fashion a mass LED retrofit plan to meet each municipality's needs and results in economy of scale retrofit savings for the municipality. *Id.*, 17-18.

2. Rebuttal. Mr. Nollenberger testified I&M is not proposing new LED-specific basic rates in this proceeding. Nollenberger Rebuttal, 36. He explained on May 31, 2019, the Company filed a 30-Day filing with the Commission requesting LED rates for tariff classes OL, ECLS and SLC. He said the Commission approved I&M's 30-Day filing on July 10, 2019. *Id.* Mr. Nollenberger responded to Mr. Seelye's claim that there are errors in I&M's proposed street lighting rates in this case. He said the proposed rate increases that Mr. Seelye identifies are specific to the basic rate components and ignores the effect of "Fuel + All Riders" that is clearly identified in each of the applicable pages of his workpaper WP-MWN-4. Nollenberger Rebuttal, 36-37. He said page 46 of WP-MWN-4 summarizes the Company's proposed total revenue change across all street lighting tariffs and shows the net effect of proposed basic SL rates, plus proposed SL rider rates equals total present revenues, within rounding, for an effective 0% increase for the overall SL class. *Id.*, 37.

Mr. Nollenberger also responded to Mr. Seelye's discussion of the impact of the change in I&M's fuel basing point on streetlighting rates. He explained in isolation, a reduction in the fuel basing point should result in a net decrease in basic rates. Nollenberger Rebuttal, 37-38. However, he said I&M's case includes the movement of various revenue recoveries from the Company's riders to its basic rates. Therefore, he said it is necessary to account for the net effect of fuel and all other riders when assessing the change in the Company's proposed basic rates. *Id.*, 38. He presented a table showing the net effect of I&M's proposed ECLS rates is an approximately 0% increase. *Id.*; Table MWN-1R.

Mr. Nollenberger disagreed with South Bend's assertion that the O&M costs included in the development of I&M's streetlighting rates are significantly overstated. Nollenberger Rebuttal, 39. He added even if Mr. Seelye was correct that the Company's full cost estimates are flawed, I&M only uses the relative relationship of those full cost estimates for each fixture to establish proposed rates that only collect the fully supported embedded costs from the Company's class cost of service study. *Id.* With respect to the PES Program rates, he explained he updated the PES conversion rates following the same methodology that was agreed upon and established in the settlement in Cause No. 44841. *Id.*, 40. Finally, Mr. Nollenberger disagreed with the recalculated Tariffs ECLS and SLS rates presented by Mr. Seelye. *Id.*, 41.

Mr. Lucas agreed with the general idea that LED street lighting technology can be beneficial. Lucas Rebuttal, 21. He said the issue is how best to implement a mass conversion from existing street lighting technology to new LED technology for those customers seeking to move to LED technology. He explained a mass conversion project requires new capital investment and this cost must be reflected in rates charged to the street lighting customer(s) involved in the mass conversion. *Id.* He said it would not be in the Company's interest or the interest of its customers for the Company to incur volume labor costs and purchase conversion materials in bulk without a commitment from the customer that it can and will accept service and the costs associated with providing that service. *Id.*, 21-22.



Mr. Lucas explained the PES Program approved in Cause No. 44841 reflects the Company's effort to facilitate mass conversion projects. Lucas Rebuttal, 22. He said while witnesses Seelye, Sommer, and Dorau criticized the PES Program, they do not dispute that I&M is offering the program in accordance with the settlement agreement approved in Cause No. 44841. *Id.* He said there are no current or forecasted participants in the PES Program, which expires at the end of 2019. Therefore, he said it is unnecessary for the Commission to address the criticisms of the current PES Program in this general rate case. *Id.*, 22. He said in Cause No. 45285, I&M proposes to continue the PES Program with updated energy savings and incremental measure costs to reflect changes since the program was first designed. He proposed I&M work with South Bend regarding their concerns with the design and implementation of the PES Program in that separate docket and not in this general rate case. *Id.*, 22-23.

3. Discussion and Finding. We begin our discussion by noting I&M is not proposing any LED-specific basic rates in this case, as such rates were previously approved by this Commission on July 10, 2019, in 30-Day Filing No. 50279. The record shows Mr. Seelye's testimony that there are "errors" in the calculation of I&M's streetlighting rates is based on an incorrect understanding of I&M's rate design. Mr. Nollenberger's rebuttal testimony explained that the net effect of proposed basic SL rates, plus proposed SL rider rates, equals total present revenues, within rounding, for an effective 0% increase for the overall SL class. Nollenberger Rebuttal, 37. Similarly, substantial evidence shows that Mr. Seelye's discussion of the impact of the lower proposed fuel basing point on streetlighting rates fails to account for the net effect of fuel and all other riders when assessing the change in the Company's proposed basic rates. *Id.*, 38.

We find South Bend's argument that I&M's streetlighting rates are overstated to be unsupported by the record. Mr. Seelye's criticism is based on his statement that the cost related to the failure of bulbs and photoelectric equipment should already be captured in I&M's depreciation rates. Seelye, 36-37; Nollenberger Rebuttal, 39. However, the initial installation of the light fixture (which is a retirement unit for I&M and thus eligible for capitalization) includes the lamp and photoelectric control (minor items of property for I&M). Nollenberger Rebuttal, 39. The record shows the entire fixture, including lamp and photoelectric control, is capitalized and depreciated over approximately 20 years. *Id.* Since the lamp and photoelectric control are both minor items of property, the cost to replace these items are charged to maintenance as incurred. The photoelectric control and the bulb are not retirement units and thus are not captured in the calculation of depreciation rates. *Id.* Further, the record shows that even if Mr. Seelye was correct that the Company's full cost estimates are flawed, I&M only uses the relative relationship of those full cost estimates for each fixture to establish proposed rates that only collect the fully supported embedded costs from the Company's class cost of service study, as calculated in WP-MWN-4. *Id.* Finally, since Mr. Seelye's proposed lighting rates for Tariffs ECLS and SLS are intended to "correct" errors that do not exist and reflect South Bend's recommended 50% class subsidy reduction we rejected above, we find South Bend's proposed alternative lighting rates should also be rejected.

With respect to the PES Program, we note the existing program is set to expire at the end of 2019 and there are no current or forecasted participants. Lucas Rebuttal, 22. In I&M's pending DSM Plan case, Cause No. 45285, I&M has proposed a revised PES Program with updated energy savings and incremental measure costs. *Id.*, 22-23. We note South Bend is a party in that

proceeding. *Re Indiana Michigan Power Co.*, Cause No. 45285, Prehearing Conference Order, p. 1 (IURC 10/29/2019) (granting City of South Bend Petition to Intervene). Accordingly, there is no need to address South Bend’s criticisms of the current PES Program in the context of this rate case.

**C. Dry Cask Storage Deferral.**

1. I&M. Mr. Williamson stated as agreed in Cause No. 44967, I&M currently defers all costs associated with dry cask storage costs that are not reimbursed by the U.S. Department of Energy (“DOE”). Williamson Direct, 56. He said I&M requests to continue this deferral and to continue to accrue carrying costs on the deferred balance using the pre-tax WACC rate approved by the Commission in this proceeding. *Id.* He explained I&M is not seeking recovery of any deferred costs in this proceeding pursuant to the Commission’s order in Cause No. 44967 and said I&M will address any related deferral in I&M’s next base case proceeding. *Id.*, 57.

2. Commission Discussion and Finding. No party objected to I&M’s request to continue deferral accounting for dry cask storage costs and we find it to be reasonable. The record shows I&M entered into a contract with the DOE under which the DOE was required to accept spent nuclear fuel and high-level radioactive waste from the Cook Plant. Williamson Direct, 56; Lies Direct, 19-20. However, the DOE has partially breached this contract and has never accepted this material, requiring Cook to store the material onsite in dry cask storage. *Id.* I&M has entered into settlement agreements with the DOE since October 2011 under which the DOE has, to date, reimbursed I&M for \$146.2 million (or 96%) of the cost of dry cask storage at Cook. Williamson Direct, 57. The record shows there are no dry cask storage costs included in the 2020 Test Year because I&M anticipates that the DOE will continue to reimburse I&M for these costs. *Id.* However, if the DOE reimbursements should cease or if ongoing costs should exceed the amount reimbursed, we find that I&M should continue to record the unreimbursed amount as a regulatory asset and accrue carrying charges on the deferred balance using the pre-tax WACC for recovery in subsequent base rate case proceedings. Accordingly, we grant I&M’s request for deferral and carrying cost authority for dry cask storage costs.

**17. Terms and Conditions of Service and Tariffs.**

1. I&M. Mr. Cooper described and supported the Company’s proposed modifications reflected in the new Tariff Book 18, including adjusting one-time service charge rates, proposing an AMI Opt-out provision, introducing new rate designs for residential customers, introducing several pilot programs and revising demand rates for specific tariffs. Cooper Direct, 3-17. He said all of the proposed changes to the Tariff Book are just and reasonable and should be approved by the Commission. *Id.*, 21.

Mr. Cooper testified the Company is adding tariff language allowing a customer to opt-out, or decline, the use of AMI technology and instead be served through a standard radio frequency meter. Cooper Direct, 7. He said this proposal includes a cost-based monthly charge to customers choosing to opt-out of the AMI meter and a one-time charge for customers that notify the Company of their preference to opt-out after the AMI meter is already installed at their residential location. He said this language recognizes the additional costs associated with the

monthly meter reading process required by opting out of AMI technology. He said I&M received approval of a similar opt-out provision in its Michigan jurisdiction. *Id.*, 8.

2. OUCC. Ms. Aguilar said I&M should offer a self-read program for AMI opt-out customers at no additional charge. Aguilar, 3, 28. She said absent a no-cost option, I&M's monthly fee is a deterrent intended to force I&M customers to convert to AMI. She further recommended progress reports for AMI opt-out. *Id.*, 4-5.

3. Intervenors. South Bend witnesses Dorau and Sommer also recommended I&M offer an AMI self-read option. Dorau, 19; Sommer, 34. Auburn witness Rutter recommended the Commission, working with I&M and the intervenors, should adopt policies and procedures to protect customer data gathered from AMI meters. Rutter, 6.

4. Rebuttal. Mr. Cooper testified I&M did not propose a self-read option because this creates a higher likelihood of meter reading errors and risks putting customers in a position that they may not want to be in. Cooper Rebuttal, 2. He discussed the challenges and difficulties associated with self-reading meters and said these issues are avoided by using I&M's meter readers and the communicating radio frequency meters for opt-out customers. *Id.*, 2-4. He stated Ms. Aguilar did not explain why quarterly reporting is necessary and expressed concern about publishing data around specific customers that have chosen to opt-out of an AMI meter. *Id.*, 5. With respect to Mr. Rutter's recommendation regarding data privacy, Mr. Cooper stated I&M has a Data Privacy Policy in place already and has dedicated a portion of its website to describe said policy in detail. *Id.*, 6.

5. Commission Discussion and Finding. The record shows many of I&M's proposed tariffs, rider modifications, rules, and regulations were unopposed by any party. Based upon the evidence of record, the uncontested proposals for I&M's tariffs, riders, rules and regulations are approved as proposed by I&M.

While no party objected to I&M's proposed AMI opt-out language, the OUCC and South Bend both proposed I&M create an additional AMI self-read option. While this would serve to shift meter reading costs from these customers to I&M's remaining customers, it would also create potential difficulties for these self-read customers. As Mr. Cooper noted in his rebuttal testimony and during cross-examination, the prospect of having individual customers take on the responsibility of reading their meters accurately and during specific periods each month presents a number of obstacles and challenges. To the extent a customer were to incorrectly read his or her meter, or fail to read it on time, the result would be billing inefficiencies or miss-billings. Cooper Rebuttal, 2-4; Tr. B-118-20, 126-27. This in turn can lead to increased administrative costs to investigate and correct any matters of concern. These issues are avoided by using I&M's meter readers and the communicating radio frequency meters for opt-out customers. Cooper Rebuttal, 4. Moreover, we note that I&M's performance metrics report includes meter reading, and the Company currently provides actual readings 99.9% of the time. *Id.*, 3. We decline the OUCC's and South Bend's invitation to shift the responsibility for this important utility function away from the Company and its trained employees. Accordingly, we decline to adopt a self-read option at this time.

The record shows I&M's AMI opt-out charges are reasonable and are cost-based. Cooper Direct, 8-9. We disagree with the OUCC's assertion these costs are "punitive" in nature. Rather, I&M's AMI opt-out charges reflect the additional meter reading expense associated with reading meters from customers who choose to opt out of receiving AMI technology. *Id.* We find I&M's opt-out charges appropriately ensure opt-out customers are allocated the costs associated with their choice. Accordingly, based on the evidence presented, we approve I&M's AMI opt-out tariff as proposed by I&M.

**18. Confidentiality.** Petitioner filed motions for protection and nondisclosure of confidential and proprietary information on May 14, 2019, September 3, and September 17, 2019, all of which were supported by affidavits showing certain documents to be submitted to the Commission contain confidential, proprietary, competitively sensitive, and/or trade secrets as defined under Ind. Code §§ 23-2-3-2 and 5-14-3-4. Docket Entries were issued on each of these motions finding such information to be preliminarily confidential, after which the information was submitted under seal. The Commission finds all such information previously granted preliminary confidential treatment is confidential and exempt from public access and disclosure by the Commission under I.C. §§ 5-14-3-4 and 8-1-2-29.

**IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:**

1. Petitioner shall be and hereby is authorized to adjust and increase its rates and charges for electric utility service to produce an increase in total operating revenues of approximately 11.06% in accordance with the findings herein which rates and charges shall be designed to produce forecasted total annual operating revenues of approximately \$162,387,782, which are expected to produce annual net operating income of approximately \$290,672,575.

2. Petitioner shall be, and hereby is, authorized to place into effect Phase I rates and charges in accordance with the findings herein for bills rendered for retail electric service on and after the effective date of this order.

3. Petitioner shall be, and hereby is, authorized to place into effect Phase II rates and charges in accordance with the findings herein for retail electric service on and after June 1, 2020.

4. I&M shall certify its net plant at December 31, 2020 and calculate the resulting Phase III rates and charges, which shall be made effective in accordance with the findings herein.

5. Petitioner shall file new schedules of rates and charges along with its revised tariff under this Cause consistent with the rates and charges approved above. Petitioner's new schedules of rates and charges shall be effective upon approval by the Energy Division.

6. Petitioner's proposed depreciation accrual rates set forth in Attachment JAC-1 and Petitioner's proposal to place these rates into effect for accrual accounting purposes are approved as set forth in this Order.

7. Petitioner's proposed three-year AMI deployment and the expenditures associated therewith shall be and hereby are approved by the Commission pursuant to Ind. Code § 8-1-2-23.

8. Petitioner is authorized to implement the AMI Rider in accordance with Finding No. 15.C.1.(e).

9. Petitioner shall make a compliance filing and submit its rider adjustment mechanism as set forth in Finding No. 10.N.1.(e) (Excess ADFIT) and is granted all necessary associated accounting authority.

10. The deferral accounting authority sought by Petitioner is approved in accordance with Finding No. 10.H.5 (*IM Plugged In*), Finding No. 10.K.4 (Major Storm Damage Restoration Reserve), Finding No. 10.N.1.(e) (Excess ADFIT), and Finding No. 16.C.2 (dry cask storage).

11. Petitioner's request for an ongoing waiver of the purchase power benchmark procedures as applied to I&M in Cause No. 43306 is hereby approved.

12. The information filed in this Cause pursuant to Petitioner's motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

13. This Order shall be effective on and after the date of its approval.

**HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR;**

**APPROVED:**

**I hereby certify that the above is a true  
and correct copy of the Order as approved.**

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Mary M. Becerra  
Secretary of the Commission