FILED
May 14, 2019
INDIANA UTILITY
REGULATORY COMMISSION

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

VERIFIED PETITION FOR GENERAL RATE INCREASE AND ASSOCIATED RELIEF UNDER IND. CODE § 8-1-2-42.7, NOTICE OF PROVISION OF INFORMATION IN ACCORDANCE WITH THE MINIMUM STANDARD FILING REQUIREMENTS AND REQUEST FOR ADMINISTRATIVE NOTICE

INDIANA MICHIGAN POWER COMPANY ("I&M", "Company" or "Petitioner") respectfully petitions the Indiana Utility Regulatory Commission ("Commission" or "IURC") for authority to increase its retail rates and charges for electric service rendered by I&M in the State of Indiana through a phase-in rate adjustment; and for approval of related relief including: revised depreciation rates; accounting relief; inclusion in rate base of qualified pollution control property and clean energy project; enhancements to the dry sorbent injection ("DSI") system; advanced metering infrastructure; rate adjustment mechanism proposals; and new schedules of rates, rules and regulations. This filing is made pursuant to Ind. Code § 8-1-2-42.7 ("Section 42.7"). I&M also requests administrative notice as stated below. In support of this Petition, I&M represents the following:

Petitioner's Corporate Status.

1. 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.

2. 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.

Petitioner's Service Territory.

3. I&M supplies electric service to approximately 468,000 retail customers in northern and east-central Indiana and 129,000 retail customers in southwestern Michigan, within a service area covering approximately 4,573 square miles. In Indiana, I&M provides retail electric service to the following 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 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.

Petitioner's "Public Utility" Status.

4. I&M is a "public utility" under Ind. Code § 8-1-2-1 and is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana.

5. I&M is also subject to the jurisdiction of the Michigan Public Service Commission and the Federal Energy Regulatory Commission ("FERC") as to electric service provided by I&M to retail customers in Michigan and to wholesale customers, respectively.

6. I&M's transmission system is under the functional control of PJM Interconnection, L.L.C., a 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 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 within the RF region.

Petitioner’s Electric Utility System.

7. 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. In order to continue to properly serve the public located in its service area and to discharge its duties as public utility, I&M has and continues to make numerous additions, replacements and improvements to its electric utility systems.

8. I&M’s property is classified in accordance with the Uniform System of Accounts as prescribed by the FERC and adopted by this Commission.

Statutory Authority for Requested Relief.

9. This Petition is filed pursuant to Section 42.7. Other provisions of the Public Service Commission Act, as amended, Ind. Code § 8-1-2-1, *et seq*., that may be applicable to the subject matter of this proceeding, include, but are not limited to: Ind. Code §§ 8-1-2-4, 6, 6.7, 10, 19, 20, 21, 23, 29, 42, 61, 68 and 71 and, to the extent necessary, Ind. Code ch. 8-1-8.7.

GAO 2013-5.

10. In accordance with the guidance provided by the Commission’s General Administrative Order 2013-5 (Rate Case Standard Procedural Schedule and Recommended Best Practices for Rate Cases Submitted under Ind. Code § 8-1-2-42.7) (“GAO 2013-5”), I&M provided its Notice of Intent to File Rate Case to the Commission on April 10, 2019. This Notice was provided at least 30 days prior the date of filing this

Petition. I&M also reached out to the Indiana Office of Utility Consumer Counselor ("OUCC") and other stakeholders to discuss the filing.

Test Year, Rate Base Cutoff Dates.

11. Pursuant to Section 42.7(d), I&M is utilizing a forward looking test period determined on the basis of projected data for the twelve (12) months ended December 31, 2020 ("Test Year"). In accordance with Section 42.7, this Test Year (which commences January 1, 2020), begins not later than 24 months after the date on which this Petition is filed. This test period is entirely within the twenty-four month period following the date on which I&M is filing its Petition.

12. I&M is utilizing the Test Year end, December 31, 2020, as the general rate base cutoff date. I&M proposes the Commission establish I&M's authorized net operating income by applying the overall weighted average cost of capital to the Test Year end original cost rate base. The Company also proposes the Test Year end original cost rate base be used as the fair value of the Company's utility property.

Submission of Case-in-Chief and Other Supporting Documentation.

13. I&M is filing its case-in-chief, including the information required by Section 42.7(b), in written form contemporaneous with this Petition. To facilitate review of the filing, I&M has attached to this Petition, as Petition Exhibits A and B, an index of issues and requests, and testimony summaries for each witness.

14. I&M has elected to file its case in accordance with the Commission's Minimum Standard Filing Requirements ("MSFRs") (170 IAC 1-5-1 *et seq.*). As recognized in GAO 2013-5, a future test year does not align with all of the Commission's pre-existing MSFRs. In accordance with the guidance in the GAO 2013-

5, I&M has provided supporting documentation in accordance with the Commission's MSFRs, modified where appropriate to conform with the forward-looking test year authorized by Section 42.7. This information is provided electronically (in Excel format where appropriate) and includes workpapers for the forecast (including the load forecast), the cost of service study, the proposed cost of equity and fair rate of return, the depreciation study and nuclear decommissioning.

15. I&M's supporting documentation also includes historical data for the calendar year 2018, the most recent audited set of financial statements at the time I&M began preparing this filing, and additional historical information by month for the period January 2019 through March 30, 2019 (the most recent month for which reviewed financial information is available at the time of this filing).

Petitioner's Existing Rates and Rate Structure.

16. I&M's existing retail rates in Indiana were established pursuant to the Commission's May 30, 2018, Order approving the settlement agreement in Cause No. 44967. Those basic rates and charges remain in effect today, as modified by various riders approved by the Commission from time to time.[1] These riders adjust I&M's rates for service to timely recover changes in certain costs associated with the provision of service.

17. 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 have passed since the filing date of I&M's most recent request for a general increase in its basic rates and charges.

[1] In this filing, I&M uses the terms "basic rates" and "base rates" interchangeably.

Petitioner's Operating Results Under Existing Rates.

18. I&M's underlying revenue requirements have and continue to change. Since its basic rates and charges were last established, I&M has continued to make significant capital expenditures for additions, replacements and improvements to its electric utility system. I&M must continue to invest in modernizing its infrastructure and service offerings to address rapid technological change and evolving customer expectations. I&M has and must continue to make significant capital expenditures for additions as a result of environmental requirements. The open access requirements applicable to I&M's transmission system impose obligations, costs and risks on I&M as a grid user and operator and require the way in which these costs are recognized for ratemaking purposes to be updated. At the same time, I&M faces the challenges of declining customer usage and the expiration of a number of wholesale contracts.

19. As a result, I&M's Test Year return upon its electric utility property is below the level required to permit I&M to earn a fair return on its electric utility property equal to that available on other investments of comparable risk, to provide revenues which will enable I&M to continue to attract capital required for additions, replacements and improvements to its electric utility property and to comply with regulatory mandates at a reasonable cost, to maintain and support I&M's credit, and to assure confidence in I&M's financial soundness. As a consequence, I&M's existing rates and charges will be insufficient to provide revenues adequate to cover its necessary and reasonable operating expenses and to provide the opportunity to earn the fair return to which I&M is lawfully entitled. I&M's existing rates, therefore, are unjust, unreasonable, insufficient and confiscatory, and should be increased.

Petitioner's Proposed Rates and Charges and Tariff Terms.

20. Adequate rates are essential to allow I&M to achieve the financial results that will be necessary to attract needed debt and equity capital on reasonable terms, to comply with environmental and other mandates, and to otherwise invest to meet the continued need for electricity within I&M's service area. I&M's filing supports the Company's ongoing effort to address aging infrastructure, secure long-term reliability, address system modernization and otherwise meet the ongoing energy and capacity needs of its customers. I&M requests that new rates and charges and the associated relief be authorized to enable I&M to realize a reasonable and adequate net operating income to render adequate and reliable service and facilities to the public.

21. As proposed in its case-in-chief, I&M requests the Commission to approve an overall annual increase in revenues from base rates and charges, including rate adjustment mechanisms, in the total amount of approximately $172 million. I&M proposes 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. I&M's proposed Phase-in Rate Adjustment balances customer and Company interests and is detailed in I&M's case-in-chief filed contemporaneous herewith and further summarized below.

Phase-In Rate Adjustment

22. As explained in the filed testimony of Company witness Jennifer C. Duncan, I&M proposes to implement the requested rate increase in phases to reasonably reflect the utility property that is used and useful at the time rates are placed

into effect. I&M's proposed phase-in rate adjustment also reflects approximately 300 MWs of wholesale contracts that are ending May 31, 2020. I&M's filing aligns the timing of its capital structure with rate base for purposes of the rate phase-in.

Rate Adjustment Mechanisms

23. The relief sought by I&M in this case includes proposals to modify or consolidate certain existing riders and an ongoing waiver of the purchased power benchmark procedures in the FAC. I&M also proposes a new rate adjustment mechanism as part of its advanced metering infrastructure proposal discussed below. These changes are driven by an attempt to address costs that are largely outside the Company's control and to provide efficient and timely cost recovery.

Advanced Metering Infrastructure ("AMI")

24. As discussed in I&M's case-in-chief, I&M intends to deploy AMI technology in its Indiana service territory. AMI deployment is forecasted to begin in the 2020 Test Year and continue through 2022, with the majority of I&M's expenditures taking place in 2021-22. I&M requests Commission approval of I&M's overall AMI deployment plan pursuant to Ind. Code § 8-1-2-23. I&M also requests, pursuant to Ind. Code § 8-1-2-42(a), approval of a new AMI Rider to track AMI deployment costs.

Other Proposals Included In Filing.

25. I&M's other proposals are indexed in Petition Exhibit A, summarized in Petition Exhibit B, and explained in the case-in-chief filed contemporaneous herewith.

Confidential Information.

26. Contemporaneous with the filing of this Petition, I&M is also filing a motion for protective order to protect certain confidential, proprietary, competitively sensitive and/or trade secret information related to I&M's filing from public disclosure. I&M has

entered into a nondisclosure agreement with the OUCC and will work together with any intervenors to negotiate an acceptable confidentiality agreement to facilitate the production of the confidential information as appropriate.

Request for Prehearing Conference and Preliminary Hearing and Procedural Schedule.

27. Pursuant to 170 IAC 1-1.1-15, I&M requests that a date for a prehearing conference and preliminary hearing be promptly set by the Commission to address procedural matters including setting a procedural schedule that will allow completion of the case within 300 days in accordance with GAO-2013-5 and Section 42.7. I&M will work with the OUCC and potential intervenors to develop an agreed procedural schedule consistent with the timeframe in the GAO. I&M plans to file any agreement separately in this case.

Customer Notification.

28. In accordance with Ind. Code § 8-1-2-61(a), I&M will publish notice of the filing of this Petition in a newspaper of general circulation published in each Indiana county in which I&M renders service. In accordance with 170 IAC 4-1-18(c), I&M will furnish to each residential customer within forty-five (45) days of this Petition, a notice which fairly summarizes the nature and extent of the proposed changes. This notice will be provided via bill messaging, bill inserts, or similar mailing. The notice will be late-filed as an exhibit.

Request for Administrative Notice.

29. Pursuant to 170 IAC 1-1.1-21, I&M requests administrative notice to be taken of the Commission's Order in Cause No. 44967 (May 30, 2018) (general rate case).

Attorneys for Petitioner.

30. The names and addresses of I&M's duly authorized representatives, to whom all correspondence and communications concerning this Petition should be sent, are as follows:

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
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WHEREFORE, I&M respectfully requests that the Commission promptly conduct a prehearing conference and preliminary hearing, make such investigation and hold such hearings as are necessary or advisable in this Cause, and thereafter make and enter an appropriate order in accordance with the 300-day time frame provided in GAO-2013-5 and Section 42.7:

1) finding that the existing rates for electric service rendered by I&M in the State of Indiana are insufficient to provide revenues to cover the reasonable and

[2] I&M will file a petition for admission of Mr. McKenzie pro hac vice with the Indiana Supreme Court.

necessary Test Year operating expenses and fair return and are therefore unjust, unreasonable, insufficient, and confiscatory;

2) determining and, by order, fixing increased rates and charges to be imposed, observed and followed commencing as soon as practicable in lieu of those so found to be unjust, unreasonable, insufficient and confiscatory;

3) authorizing I&M to revise and place into effect for accrual accounting purposes its depreciation rates as proposed in its evidence herein;

4) continuing the inclusion in rate base of the Company's prepaid pension asset;

5) including I&M's qualified pollution control property and clean energy project in the revenue requirement to be established in this Cause;

6) including the enhancements to the dry sorbent injection ("DSI") system in the revenue requirement to be established in this Cause;

7) updating nuclear decommissioning expense as proposed by I&M;

8) approving the Company's deployment of advanced metering infrastructure (AMI) and approving the AMI Rider to track AMI deployment costs;

9) approving the accounting relief and other requests identified in <u>Petition Exhibits A and B</u> and identified in I&M's evidence herein;

10) approving the Company's other rate adjustment mechanism proposals, as proposed in I&M's evidence herein;

11) approving I&M's proposed rate design including the changes to the Residential customer rate design;

12) approving and authorizing I&M to implement various changes in the terms, conditions and provisions of I&M's tariff for electric service rates as proposed in I&M's evidence;

13) approving I&M's Test Year end rates and proposal to phase in the new rates as discussed in I&M's case-in-chief;

14) authorizing and approving the filing by I&M of new schedules of increased rates and charges for electric service so as to provide just, reasonable, sufficient and nonconfiscatory rates; and

15) granting such other and further relief to I&M as may be appropriate and proper.

Dated this 14th day of May, 2019.

Respectfully submitted,

INDIANA MICHIGAN POWER COMPANY

By: ______________________
Toby L. Thomas
President and Chief Operating Officer

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
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Attorneys for INDIANA MICHIGAN POWER COMPANY

STATE OF INDIANA)
) SS:
COUNTY OF ALLEN)

AFFIDAVIT

Toby L. Thomas, being first duly sworn, upon oath, deposes and says that he is the President and Chief Operating Officer of Indiana Michigan Power Company, the Petitioner in the above-entitled Cause; that as such he executed the above and foregoing Petition and has authority so to do; that he has read said Petition and knows the contents thereof; and that the statements and representations therein contained are true to the best of his knowledge, information and belief.

Toby L. Thomas

Subscribed and sworn to before me, a Notary Public, in and for said County and State this 19 day of May, 2019.

Regiana M. Sistevaris, Notary Public

I am a resident of Allen County, Indiana.
My commission expires: January 7, 2023

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic email, hand delivery or First Class, United States Mail, postage prepaid this 14th day of May, 2019 to:

William I. Fine
Abby R. Gray
Indiana Office of Utility Consumer Counselor
Office of Utility Consumer Counselor
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Jeffrey M. Peabody

DMS 14412421v1

Indiana Michigan Power Company
2019 Rate Case
Index of Issues, Requests, and Supporting Witnesses[1]

Subject	GENERAL	Supporting I&M Witness
Test Year	Twelve Months Ended December 31, 2020.	• Williamson.
Historical Base Period	Twelve Months Ended December 31, 2018.	• Williamson.

REVENUE REQUIREMENT		
Subject	I&M Request	Supporting I&M Witness
Overall Revenue Increase	• Total annual increase in revenue of approximately $172 million, or 11.75% to be phased in over three steps. • Phase-In Rate Adjustment (PRA): o Phase I: $82.5 million or 5.63%. o Phase II: $129 million or 8.81%. o Phase III: $172 million or 11.75%.	• Thomas (overview). • I&M Financial Exhibit (details). • Williamson (policy). • (See "Cost of Service and Rate Design" below for description of PRA; see also Ross (general regulatory accounting and various adjustments).)
Advanced Metering Infrastructure (AMI)	• Preapproval under IC 8-1-2-23 of three-year plan (2020-22) to rollout AMI in I&M's Indiana service territory. • Timely recovery of AMI deployment costs through new AMI Rider. • Cost-based AMI opt-out tariff. • Standard retirement accounting for AMR meters currently installed in Indiana service territory.	• Thomas (overview). • Isaacson (deployment, operational benefits). • Lucas (technology, customer engagement and programs). • Williamson (regulatory treatment). • Cooper (AMI opt-out). • Cash (AMR retirement).
Depreciation	• Set new depreciation rates and reflect the resulting depreciation expense in base rates based on depreciation study. • Adjust Rockport Unit 2 selective catalytic reduction (SCR) depreciation rate to align with expected end of life of Rockport Unit 1 in 2028.	• Cash (depreciation). • Thomas (SCR overview).

[1] This Index of the Company's case-in-chief is intended to highlight issues and is not an exhaustive list of I&M's requests in this proceeding. A complete account of I&M's requested relief can be found in I&M's case-in-chief, including but not limited to I&M's petition, testimony, exhibits, workpapers, and MSFR responses. The I&M Financial Exhibit provides an additional index.

REVENUE REQUIREMENT		
Subject	I&M Request	Supporting I&M Witness
Distribution	• Reflect forecasted distribution O&M and capital in rates, including programs and projects in I&M's 2019-20 Indiana Distribution Plan: o Continue vegetation management program approved in Cause No. 44967 (hereinafter 44967). o Asset renewal and reliability program. o Customer service, city and state requirements and other. o Major projects. o Risk mitigation program. o Grid modernization program (including AMI). • Continue deferral accounting authority for major storm restoration cost reserve as in 44967.	• Isaacson (distribution O&M and capital). • Williamson (major storm reserve accounting).
Economic Development Programs	• Continue the third component of the Economic Impact Grant (EIG) Program established in 44967 which establishes annual funding for grants ($137.5k/year reflected in rates). • Continue economic development rider as clarified with no termination date. • Approval of new pilot programs – (a) Apprenticeship and Training pilot ($350k/year for two years) and (b) Building Development pilot ($150k/year for two years).	• Lucas (programs) • Cooper (associated tariff changes).
Electric Transportation (IM Plugged In Pilot Program)	• Approval of residential plug-in electric vehicle (PEV) incentives, including overnight charging rate and $500/port incentive for charging equipment (2-year pilot; annual cap of 1,000 customers, 1,000 ports, $500k). • Approval of multiunit dwelling PEV incentive of $250/port or CIAC reduction (2-year pilot; annual cap of 100 customers, 400 ports, $100k). • Approval of fleet and workplace charging PEV incentive of $250/port (2-year pilot; annual cap of 100 customers, 400 ports, $100k). • Deferral of program costs.	• Lehman (program). • Cooper (associated tariff changes). • Williamson (deferral).

REVENUE REQUIREMENT		
Subject	I&M Request	Supporting I&M Witness
Financial Forecast	• Set rates based on I&M's Test Year financial forecast. • Reflect forecasted O&M and capital investments in rates based on I&M's work plans.	• Lucas (overall development of O&M and capital forecast). • Heimberger (forecasting model). • Lies (nuclear O&M and capital). • Kerns (non-nuclear generation O&M and capital). • Isaacson (distribution O&M and capital). • Ali (PJM costs). • Burnett (load forecast).
Generation (Fossil, Hydro, and Solar))	• Reflect forecasted generation O&M in rates. • Reflect forecasted generation capital investment in rates, including: o Rockport Unit 2 SCR (CPCN granted in Cause No. 44871). o Coal Combustion Rule (CCR) compliance. o Enhanced DSI (adjustment for capital expense and O&M (consumables)). • Adjust Test Year consumables expense to reflect ongoing level; embed Test Year consumables and allowances expense in base rates and track over/under expense through environmental cost rider (ECR).	• Kerns (generation O&M and capital investment, variability of consumables and allowances expense). • Thomas (consent decree modification for Enhanced DSI). • Williamson (adjustments for Enhanced DSI capital and O&M, tracking consumables and allowances).
Nuclear Decommissioning and Spent Nuclear Fuel Trust	• Increase Indiana retail annual contribution to Nuclear Decommissioning Trust (NDT) to $10M to target 90% probability of have sufficient funds. • Continue current $0 funding level for Spent Nuclear Fuel Trust (SNFT) and adjust permissible trust investments for the assets that exceed the Indiana jurisdictional liability by 1.05 so that they align with the guidelines for the Decommissioning Trust.	• Thomas (overview) • Hill (NDT likelihood of success, SNFT investments). • Knight (nuclear decommissioning cost study). • Lies (nuclear decommissioning overview).

REVENUE REQUIREMENT		
Subject	I&M Request	Supporting I&M Witness
Nuclear Operations	• Reflect forecasted nuclear O&M in rates. Reflect forecasted nuclear capital investment in rates, including in-service Life Cycle Management (LCM) projects and other investments. • Continue the deferral of dry cask storage costs not reimbursed by the DOE as in 44967. • Amortize and reflect in rates costs of compliance with Clean Air Act Section 316b rules ("316b").	• Lies (nuclear O&M and capital investment, description of dry cask storage and 316b). • Williamson (LCM Rider, dry cask storage deferral, regulatory treatment of 316b).
Ongoing and New Customer Assistance Programs	• Continue following programs established in 44967: o Energy Share Program with $250k annual funding reflected in rates. o Low Income Weatherization Program with $50k annual funding reflected in rates. o Neighbor to Neighbor Program with $50k annual funding reflected in rates. • Low Income Arrearage Forgiveness Pilot Program as agreed in 44967. • Establish new Income Qualified Safety & Health Pilot Program to address safety and health issues that prevent energy audits with $100k annual funding reflected in rates.	• Lucas.
Prepaid Pension Asset	• Continue to reflect in rate base.	• Hill (description of pre-paid pension). • Williamson (regulatory treatment).
Return on Equity (ROE)	• Authorize 10.5% ROE.	• Hevert.
Taxes	• Reflect forecasted Test Year tax expense in base rates. • Apply gross revenue conversion factor (GRCF). • Over/under deferral for excess normalized accumulated deferred federal income taxes (ADFIT) once non-normalized excess ADFIT are fully amortized pursuant to settlement in 44967. • Reflect non-normalized excess ADFIT unamortized balance in rate base to account for jurisdictional differences in amortization rate.	• Kelly (tax expense, ADFIT, GRCF). • Williamson (ADFIT deferral, non-normalized excess ADFIT unamortized balance in rate base).

REVENUE REQUIREMENT		
Subject	**I&M Request**	**Supporting I&M Witness**
Weighted Average Cost of Capital (WACC)	• Authorize forecasted WACC applied to original cost rate base.	• Messner (overall WACC calculation, financing activity). • Heimberger (equity balance). • Kelly (ADFIT balance). • Hevert (ROE).
Wholesale Contract Expiration	• Annualize effect of expiration of wholesale contracts on May 31, 2020. • Credit PRA to reflect IMMDA contracts through May 31, 2020).	• Thomas & Williamson (overview). • Nollenberger (annualization adjustment). • Duncan (rate credit component of PRA).

COST OF SERVICE AND RATE DESIGN		
Subject	**I&M Proposal**	**Supporting I&M Witness**
Class Cost of Service Study (CCOSS)	• Use of same allocation methodology as proposed by I&M in 44967.	• High (CCOSS, allocation factors).
Jurisdictional Cost of Service Study (JCOSS)	• Use of same study approach as in 44967. • New demand and energy allocation factors "Excluding Shopping" to reflect customer choice in Michigan service territory.	• Duncan.
Overall Rate Design	• Allocation of revenue increase to eliminate 25% of current subsidies. • Better alignment of residential fixed costs with rate design through approval of: o $15 monthly service charge. o Declining block rate proposal. • New optional residential demand tariff (Tariff RSD).	• Nollenberger (rate design). • Cooper (Tariff RSD).
Phase-In Rate Adjustment (PRA)	• Phase-in rate adjustment (PRA) credit for rate base additions during Test Year as in 44967. • I&M to certify actual Test-Year-end rate base pursuant to same procedure as in 44967. • Additional phase-in credit for revenue associated with IMMDA contracts ending May 31, 2020.	• Duncan (description of PRA, calculation of credits). • High (Phase-In COSS). • Nollenberger (PRA rate design).

COST OF SERVICE AND RATE DESIGN		
Subject	I&M Proposal	Supporting I&M Witness
IM Green Renewable Energy Rider	• Consolidate existing Green Power Rider and Renewable Energy Option into single *IM Green* tariff voluntary offering that will offer customers the ability to purchase Renewable Energy Certificates (RECs) as a percentage of usage at an indexed market rate. • Option for large customers to enter into custom contracts under *IM Green* program.	• Lucas (support for program). • Cooper (tariff changes).
Other Rider Proposals	• DSM/EE Rider – Remove costs/revenues from Test Year forecast and continue to track costs, including cost of DSM/EE plan for 2020 and beyond to be addressed in separate docket. Adjust rider to reset net lost revenues and to reflect additional DSM/EE-related capital included in base rates. • Environmental Cost Rider (ECR) –Track over/under Test Year level of consumables and allowances embedded in base rates; continue tracker recover of Rockport Unit 2 SCR costs until reflected in base rates. • FAC – Reset level of costs embedded in base rates (base cost of fuel or basing point) based on Test Year forecast, continue waiver of purchased power benchmark on ongoing basis and continue crediting customers for participation in voluntary renewable programs. • LCM Rider – Continue as in 44967 but with Test Year end in-service LCM capital investments reflected in base rates via PRA. • OSS/PJM Rider – o Continue to track off-system sales margins (OSS) in OSS/PJM Rider with 95%/5% Customer/Company sharing with no margins embedded in base rates as in 44967. o Continue to track all PJM NITS costs in OSS/PJM Rider with no PJM NITS costs embedded in base rates as in 44967; eliminate cap and sunset. o Embed new Test Year level of PJM non-NITS costs in rates and continue to track over/under embedded level in OSS/PJM Rider as in 44967. o Embed capacity performance insurance costs resulting from PJM Fixed Resource Requirement in base rates and track over/under embedded level in OSS/PJM Rider. • Resource Adequacy Rider (RAR) – Continue as in 44967 with new Test Year level of non-FAC purchased power costs embedded in base rates; eliminate cap and sunset.	• Williamson (changes to riders and ongoing waiver of purchased power benchmark). • Heimberger (FAC basing point). • Thomas (capacity performance insurance).

COST OF SERVICE AND RATE DESIGN		
Subject	I&M Proposal	Supporting I&M Witness
Terms and Conditions of Service and Tariffs	• New miscellaneous service charges and meter tampering fee. • New data privacy policy. • Treat EZ Bill program costs and revenues as above the line like other I&M tariff offerings (no costs or revenues reflected in rates in this proceeding).	• Cooper (service charges, privacy policy). • Williamson (EZ Bill accounting).
Transmission Costs	• Embedded Test Year level of non-NITS PJM costs in base rates. • Track all NITS costs in OSS/PJM Rider with no cap or sunset.	• Williamson (PJM Rider). • Ali (transmission investment, PJM cost forecast).

Indiana Michigan Power Company
2019 Rate Case
Summary of Case-In-Chief Testimony[1]

1. Toby L. Thomas, President and Chief Operating Officer of Indiana Michigan Power Company (I&M). I&M requests Commission approval of an overall annual increase in revenues of approximately $172 million, or 11.75%. The Company proposes to phase the increase in over three steps. The initial step will reflect an increase of $82.5 million, or 5.63%.

I&M is an operating company subsidiary of American Electric Power (AEP) and is a member of the AEP – East Zone and the PJM Regional Transmission Operator (RTO). I&M provides electric service to approximately 468,000 retail customers in northern and east-central Indiana. The Company's generating resources include the Cook Nuclear Plant and the Rockport Plant. The Company also owns and operates solar and hydroelectric facilities and has wind energy under contract.

The key challenges facing I&M include how to continue to provide reliable electric service at a comparatively low price when costs are rising, customer needs are changing, technology is rapidly evolving and environmental regulation remains uncertain.

In the past, regulators and companies were able to rely on increasing kWh sales to mitigate, at least in part, the impact of the difference in time between the time an investment was made and the time when it is recognized in rates. We now operate in a world of flat or declining load and no longer have the ability to rely on load growth to absorb cost increases.

The reality is that I&M's kWh sales will continue to be relatively flat for the foreseeable future due to technological change, energy efficiency standards and behind-the-meter energy options. I&M has worked hard to responsibly grow our business by attracting and retaining customers and we are even more committed to supporting the economic development of the communities in which we serve.

If customers are sent incorrect price signals that do not properly reflect the predominately fixed cost nature of our business, they will choose suboptimal alternatives that will erode revenues needed to support the operation of the grid. In the face of ongoing technical change, it is imperative that the design of our rates does not over time create unwarranted cost shifts from one set of customers to another. We must improve our rate design to address the impact of distributed energy resources and to send appropriate price signals to our customers.

While technological advancements and having alternatives can be a positive, it is nonetheless a dramatic change that companies, customers and regulators should recognize and manage in a way that benefits all concerned. It is important to recognize

[1] Together with the index of issues and requests in Petition Exhibit A, this summary is provided to facilitate review of the Company's filing and is not intended as an exhaustive compilation of the matters addressed in the Company's testimony.

this in setting rates because not doing so can adversely affect the Company and our remaining customers.

We can and should continue our efforts to establish rates based on cost causation principles and to transition to a rate design that more accurately reflects the fixed and variable cost of the service we provide. That way, customers who may choose to reduce their individual volume of electricity usage through self-generation will not shift their cost of service to the remaining customers who choose not to.

Economic development remains vitally important to our communities and all of our customers. Company witness Lucas addresses the Company's proposals in this case to continue our support of economic development.

As discussed by Company witness Lehman, the developing market for electric vehicles provides another opportunity to improve the Company's load and load shape. If we can integrate this load efficiently all customers benefit.

We appreciate the ability to use a forward-looking Test Year and the Commission's approval of timely cost recovery mechanisms for environmental costs, energy efficiency, purchased power (including wind and solar energy), and PJM costs, as well as our ongoing investment in Cook and Rockport Plants. These rate adjustment mechanisms encourage investors and enable projects to be funded at a reasonable cost of capital. As shown by Company witness Ali, the PJM Rider is particularly important due to the increasing cost of transmission service within PJM. I&M seeks to continue the timely recovery of costs because the proposed rate adjustment mechanisms are an important tool in our effort to meet these and other ongoing challenges while providing reliable service to our customers.

Some of the key changes underlying the need to adjust rates include the termination of wholesale contracts that have contributed revenues used to reduce the retail revenue requirement. Additionally, there have been changes in I&M's depreciation rates and nuclear decommissioning expenses. Another key change includes average annual capital expenditures of $616 million to serve customers, recognize innovations that are underway to automate and enhance the reliability of I&M's service, and comply with environmental requirements, including Section 316b of the Clean Water Act and the Federal Consent Decree governing the Rockport Plant.

The investments reflected in the Company's filing, including projects at the Cook Nuclear Plant and the Rockport Plant, and the deployment of AMI, are necessary to allow the Company to meet the ongoing need for service and facilities and to continue to build the foundation for ongoing technological advancement and evolving customer service needs.

I&M has continued to evaluate investments that would be a cost effective means of meeting environmental requirements. After a thorough investigation, I&M determined that there was an innovative approach that could allow it to achieve the same environmental benefits of the Third Modification to the Consent Decree in a more cost-effective manner.

A key component of that alternative approach was to enhance the effectiveness of the DSI equipment already in place. After extensive and lengthy discussion and negotiations with the parties to the Consent Decree, the parties reached an agreement in principle that would, among other things, avoid the requirement to install dry scrubbers on both Rockport 1 and Rockport Unit 2, which installations may have otherwise occurred in 2025 and 2028. I&M expects that agreement will be finalized and presented to the Federal Court soon. If approved by the Federal Court, the Fifth Modification to the Consent Decree would require the installation and operation of the Enhanced DSI Project on Rockport Unit 2 by June 1, 2020 and Rockport Unit 1 by December 31, 2020. The cost to install the Enhanced DSI Project is estimated to be approximately $13 million, which is significantly less than the cost of a dry scrubber. The Enhanced DSI Project is a reasonable means of maintaining the availability of relatively 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.

Ever since AMI emerged, the Company has monitored the development of smart infrastructure, exploring its potential use and assessing how and when to move forward with AMI deployment. AMI technology has now matured as expected and customers have become accustomed to digital technology and real time access to data. Customers expect energy companies to provide them with proven technology that can make their experience better. We can improve our service to them by modernizing the grid and enhance their use of our service by developing innovative products and services. Moreover, our AMR meters are at the point where they are in need of replacing. Given the age of the existing meters, we considered whether to continue to replace failing meters with AMR or move to the next generation of technology.

The Commission has previously encouraged electric utilities to examine smart technologies and demand response opportunities. In Indiana and across the country, companies have already transitioned to AMI and we likewise have the responsibility to maintain our facilities in a state of efficiency corresponding to the progress of the industry. Our experience and knowledge of AMI technology tells us that investing in that technology can provide many benefits to the distribution system and our customers and that we have reached the appropriate time for deployment of AMI in I&M's service area. Consumer demand for services reliant on two-way communications has also evolved and I&M can take advantage of the lessons learned from AMI deployment by our AEP affiliated operating companies in other states. Taken together, all of these factors support the proactive move to AMI at this time.

In our last rate review, the Company discussed the benefits of AMI and the Company's effort to prepare to fully integrate this technology. In this current case, we explain our proposed deployment of AMI systems. Company witness Isaacson discusses the AMI project from an operational standpoint. Company witness Lucas explains how the AMI technology will provide access to data that I&M will use to educate and better position customers to make informed decisions regarding their energy usage. This general rate case is necessary to support the Company's effort to take advantage of AMI technology, which in turn will lay the foundation for a customer-facing, innovative energy grid.

I&M requests the Commission to approve the three-year AMI deployment project, authorize timely cost recovery through the AMI Rider presented by Company witness Williamson, and approve Company witness Cash's proposal regarding meter depreciation. Company witness Cooper discusses the Company's AMI opt-out tariff provision that will allow a customer to opt out, or decline, the use of this AMI meter and instead be served through a Radio Frequency (RF) meter. Our experience with AMI technology indicates that the percentage of customers who seek opt out will be small and this provision reasonably accommodates this customer segment.

Three years are 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. A period of less than three years is not sufficient to accomplish the full scope of I&M's AMI deployment proposal in this case. A longer deployment period is not desirable because a mixture of AMI and AMR meters in an area is less efficient. In addition, a longer period would decrease the efficiency of the roll out and delay the operational and customer benefits we are seeking to achieve.

The Company is keenly focused on maximizing the value of the service we provide to our customers. One way we seek to achieve this is by mitigating cost increases where possible without negatively impacting service quality or accepting unreasonable risk to infrastructure or safety. Our comparatively low rates reflect that this focus is not new, it has long been part of our culture. We continually work to keep our business efficient through digitization and automation and by engaging our employees on better ways to operate.

As we work to meet our customers' energy needs, it is critical that the Company's financial health and integrity be maintained. To achieve this, we ask the Commission to approve the proposed package of rates and rate adjustment mechanisms so as to allow I&M an opportunity to earn an authorized rate of return that recognizes I&M's operating characteristics and to recover capital and operating expenses in a timely manner.

As we move closer to the retirement of the Cook Plant, it is appropriate to update the nuclear decommissioning expense so as to match these costs, to the extent practicable, to the period the units are in service. To provide assurance that this objective is met through the rates charged during the service life of the Cook Plant, the Company proposes to increase the annual decommissioning expense to $5 million for each Cook Unit, for a total annual amount of $10 million, to target a 90% probability of having sufficient funds. The 90% probability is a reasonable step toward the goal of reflecting in rates a nuclear decommissioning that has a 100% funding probability, as we continue to move toward the end of the license lives.

Similarly, it is appropriate to update the Rockport Plant depreciation expense so as to match these costs, to the extent practicable, to the period the units are in service. In Cause No. 44967, I&M explained that the Rockport Unit 2 Lease expires in December, 2022 and I&M did not then believe that extending the term of the Lease was advisable. I&M also advised the Commission that the date through which Rockport Unit 1 can be expected to be in operation with any reasonable degree of certainty is December 2028.

While we continue to assess options regarding the Lease, the Company's expected end of service life of Rockport Unit 1 continues to be December 31, 2028 and the Company is assuming in our current IRP process that the lease of Rockport Unit 2 will not be extended. The Company's proposed depreciation rates are consistent with these previously established service lives for the Rockport units and have been updated to reflect remaining investment, including the Rockport Unit 2 selective catalytic reduction (SCR) system, which the Company proposes to depreciate over the expected remaining life of Unit 1 (2028).

PJM's capacity performance rules monitor the reliability of a PJM member's capacity resources to ensure these resources are available to serve customer energy requirements. The rules, which include Non-Performance Charges in the event a generator does not meet PJM's capacity performance requirements, apply to I&M beginning June 1, 2019 and during a PJM Emergency or Performance Assessment Interval (PAI). Because a generating unit can trip out of service unexpectedly due to factors beyond the Company's reasonable control, it is reasonable to take steps to mitigate exposure to the Non-Performance Charge. 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. Given I&M's fleet operating history, Capacity Performance Insurance, which is procured before each PJM Delivery Year, currently costs about $1.00/MW-day with a reasonable deductible and policy loss limit. Given the annual cost of insurance is a fraction of the cost of a Non-Performance Charge for a large unit, and multiple PAIs can be assessed in a given year (multiple events/year), I&M insures this risk to protect our customers and the Company. Therefore, this reasonable and necessary cost of being a member in PJM should be recovered through the PJM Rider, which is the ratemaking mechanism used to recover other PJM costs.

Company witness Nollenberger presents the Company's proposed rate design for residential service. The Company proposes to increase the residential monthly service charge from $10.50 to $15.00. We also propose to address the remaining fixed costs that are not reflected in the service charge through a declining block volumetric kWh charge structure. Importantly, it should be recognized that the percentage increase in the service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill. Furthermore, 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. If I&M's rates are not properly designed, some customers will be incented to avoid fixed costs buried in the variable charge, leaving those fixed costs to be spread among the other customers.

Under I&M proposed rate design, the total bill for all customers will better reflect the underlying cost of service. Additionally, the proposed rate design provides benefits for those low income customers most dependent on electricity while remaining fair to low income low usage customers and retaining significant opportunity for energy efficiency.

We recognize that it is difficult for some customers to pay their electric bills, and we continue to offer payment assistance programs. I&M also works with many private and non-profit community-based local and federal organizations that provide assistance to low-income residents. In addition, I&M offers energy efficiency programs to help customers reduce their energy usage. The deployment of AMI will give our customers better insight into their energy usage. This in turn will allow informed decisions and opportunities for customers to reduce their electric bill by changing their use of electricity. Finally, the Company proposes to continue many of the collaborative pilot programs established pursuant to the Settlement Agreement approved in Cause No. 44967 and establish a new Income Qualified Health & Safety Pilot Program to address health and safety needs of customers to enable better use of other critical customer assistance programs. Company witness Lucas addresses these programs.

The new residential service offerings include a new residential demand metered service pilot (Tariff R.S.D.). This pilot will provide customers an additional service option that may fit their usage profile and will allow the Company to gain experience with a residential tariff with demand components. As discussed by Company witness Cooper, this optional pilot will be limited to 4,000 customers, which is approximately one percent (1%) of the Company's total Indiana residential customer base.

The Company also seeks to support the electrification of transportation because doing so is beneficial to our customers. Company witness Lehman discusses the Company's comprehensive program, "IM Plugged In", which is designed to support the expansion of plug-in electric vehicles (PEV) at scale by aligning customer incentives for off-peak charging to simultaneously provide benefits to PEV drivers and all I&M customers. Company witness Cooper explains the Company's proposal to expand its service offering for residential customers who need to charge PEVs. This tariff will provide eligible customers an opportunity to reduce their monthly billings by installing a submeter and charging their PEV during off-peak hours and weekends.

Finally, as discussed by Company witness Lucas, the Company proposes to consolidate its voluntary 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 Renewable Energy Certificates (RECs). Company witness Cooper presents the proposed tariff which includes a custom contract option for large customers.

In conclusion, the electric business continues to change as a result of environmental regulation, economic conditions, evolving technology and changes in the way our customers use electricity and want to be served. I&M's goal is to invest wisely, operate our business efficiently, and provide a customer experience that serves customers the way they want to be served. We must continue our efforts to rectify our rate design and expand our service offerings so that customers will rationally choose I&M as their energy service provider and Indiana as a place to live and work. I&M's current rates are not sufficient to cover the Test Year cost of providing service and it is I&M's responsibility to seek rate relief to support our ongoing effort to address aging infrastructure, secure long-term reliability and resiliency, enhance the service we provide through new technology and automation, and otherwise meet the ongoing energy and capacity needs of our customers. The proposals I&M makes in this case allow us to continue to embrace technology advancements and use them to support economic development and innovation for the benefit of customers, both in the short-term and while the future unfolds.

We ask the Commission to approve a revenue requirement and design rates based on sound cost of service and ratemaking principles. We also ask the Commission to find that I&M's proposal is a balanced, reasoned and rational solution to the Company's need for both cost recovery and a reasonable opportunity to earn a reasonable return, while we continue to fulfill I&M's duty to provide reliable electric service and facilities to our customers.

2. Andrew J. Williamson, Director of Regulatory Services Indiana Michigan Power Company: I&M proposes the Commission authorize recovery of I&M's cost to serve customers using the forward-looking calendar year test year of January 1, 2020 through December 31, 2020 (Test Year). This cost recovery will be implemented through a combination of base rates and rate adjustment mechanisms. I&M's overall requested rate relief for the Test Year is approximately $172 million, or approximately 11.75%. I&M proposes to implement the requested rate increase in three steps through the Phase-In Rate Adjustment (PRA) process. In Phase I, revenue would increase by approximately $82.5 million or 5.63%. In Phase II, revenue would increase by approximately $129 million or 8.81%. The overall increase identified above would be implemented in Phase III, which would commence January 1, 2021.

I&M's Financial Exhibit A shows the calculation of the revenue increase. In accordance with the GAO-2013-5 and the Minimum Standard Filing Requirements (MSFR), the Company has presented substantial support for the revenue increase and related relief. This is the same level of support provided in the Company's last general rate case (Cause No. 44967) as well as other past cases.

Many of the Company's proposals reflect a continuation of existing rate structures and processes. For example, I&M proposes to implement the rate increase in phases consistent with the PRA used to implement rates resulting from our last general rate case. The PRA proposal also reflects a revenue requirement credit to provide retail customers the benefit of the Indiana Michigan Municipal Distributors Association (IMMDA) wholesale contracts through the end of their term (May 31, 2020). The Company also proposes to continue both the Major Storm Restoration Reserve and the Dry Cask Storage deferral, and to continue to include the prepaid pension asset in rate base consistent with the treatment authorized in the Company's last two rate cases (Cause Nos. 44075 and 44967).

Similarly, I&M proposes to retain all existing rate adjustment mechanisms (i.e. riders) with certain modifications and to add one new mechanism -- the Advanced Metering Infrastructure (AMI) Rider. The AMI project lays the foundation for substantial customer and system benefits as discussed by Company witnesses Thomas, Isaacson and Lucas. The new AMI Rider provides the regulatory support necessary for this significant capital investment.

The Company's proposals for its ongoing rate adjustment mechanisms include the following:

1. DSM/EE Rider: To recognize that I&M's demand side management/energy efficiency (DSM/EE) plan for 2020 and beyond will be addressed in a separate docket, we have removed the associated costs from the Test Year and propose to recover these costs through the DSM/EE Rider based on the outcome of the separate DSM/EE case.

2. ECR: Consumables and allowances expenses are much like fuel costs: the total amount of consumables and allowances expenses incurred by the Company each year is largely outside the Company's control and can vary considerably based on how much Rockport operates and changes in operation of environmental control equipment. Therefore, I&M proposes that the Environmental Cost Rider (ECR) be used to track the consumables and allowances costs the Company incurs in operating its generating assets for the benefit of its customers.

3. FAC: With respect to the fuel adjustment clause (FAC), the Company seeks to update the base cost of fuel, to continue the previously approved waiver of the purchased power benchmark on an ongoing basis, and continue crediting customers for revenues associated with participation in I&M's voluntary renewable programs.

4. LCM Rider: I&M proposes to coordinate the LCM (Life Cycle Management) Rider with the new rates established in this case in essentially the same way we did this in our last rate case. In other words, I&M's proposed base rates in this proceeding include LCM plant that is forecasted to be placed in service as of Test Year end and the PRA will be used to reflect this new in-service plant. The remaining LCM Project capital-related costs will be recovered through the LCM Rider until the LCM Project is fully completed and reflected in base rates.

5. OSS/PJM Rider: I&M's PJM costs remain significant, variable, and largely outside the utility's control. I&M is proposing that the Off System Sales (OSS)/PJM Rider remain consistent with the structure agreed to in the settlement approved in Cause No. 44967 with the exception of removing the sunset provision and cap on certain PJM Network Integration Service (NITS) charges, and commence tracking the cost of PJM Capacity Performance insurance, which is a new cost incurred as a result of PJM requirements. Restricting the recovery of reasonable and necessary costs incurred to provide service to customers is unnecessary and potentially harmful to the Company and its customers. The OSS/PJM Rider structure proposed by the Company continues sharing of 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. Continuing to share OSS margins 95/5 (customer/Company) provides an incentive for the Company to maximize the benefits of OSS for both the Company and its customers.

6. Resource Adequacy Rider (RAR): The RAR, in conjunction with the FAC, ensures that rates only reflect the actual cost of purchased power that I&M incurs to provide service to customers. As agreed in Cause No. 44967, the RAR tracks the incremental non-fuel purchased power costs that I&M incurs above or below the level of such costs embedded in base rates. To recognize that these costs continue to be significant in amount and subject to variability due to factors largely outside of I&M's control, I&M proposes to continue this structure with no cap or sunset.

In order for the Test Year to reasonably represent ongoing costs and revenues, the Company's filing includes various adjustments, normalizations and annualizations, each of which is identified in I&M's Exhibit A. This testimony supports adjustments to:

- to reflect the enhancements to the DSI system at Rockport;
- to recognize the study costs incurred for the Cook Nuclear Plant's compliance with the Clean Water Act Rule 316b;
- to remove lobbying/legislative expenses associated with the Indiana Energy Association (IEA); and
- to reduce Total Company PJM transmission charges for the estimated amount that will be billed to Michigan Choice customers.

For purposes of this rate case, most deferred balances, including rate case expense and nuclear decommissioning study expense, are amortized over a period of two years as this period represents the most likely period between re-setting base rates in this case. However, the Cook Nuclear Plant 316b compliance study costs are amortized over a period of 15 years, which reasonably approximates the remaining license life of the Cook Plant.

This testimony addresses two requests for new deferral authority. One request concerns the transportation electrification program (IM Plugged In) discussed by Company witness Lehman and the other concerns the ongoing implementation of the Tax Cuts and Jobs Act of 2017 (TCJA) excess ADFIT (accumulated deferred federal income tax) settlement agreement approved in Cause No. 44967. The first deferral is sought because the level at which customers will participate in I&M's transportation electrification program is difficult to predict. The second deferral is proposed to clarify the ongoing treatment of normalized and non-normalized excess ADFIT so that customers will receive the agreed benefit of the Settlement Agreement approved in the Company's last rate case.

Finally, I&M's EZ Bill Program 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. The settlement agreement for the EZ Bill Program approved in Cause No. 45114 provided that the issue of whether any EZ Bill Program revenues or costs can or should be accounted for above-the-line will be addressed in I&M's next base rate case. The Company proposes that EZ Bill Program costs and revenues be accounted for above the line. This is consistent with the treatment of the revenues and costs of I&M's other tariff offerings.

Commission approval of the Company's proposed revenue increase through the package of base rates and riders presented in the Company's filing is necessary to ensure I&M is provided a reasonable opportunity to recover its cost to serve customers, including a fair return on its underlying investments used to serve customers. The regulatory support sought by the Company is important to the ongoing provision of retail electric service. The Test Year commences January 1, 2020. I&M asks the Commission to issue an order within 300 days in accordance with Section 42.7 and GAO 2013-5.

3. David A. Lucas, Vice President Finance and Customer Experience Indiana Michigan Power Company (I&M). This testimony explains and supports the forecast approach and methods used to develop the operation and maintenance (O&M) expenses and capital expenditures included in I&M's financial forecast for the Test Year, supports the customer experience, economic development and renewable programs I&M is proposing in this case; and supports the customer engagement and education plan related to I&M's AMI deployment in Indiana.

I&M uses the forecasting process as a forum to engage leaders across the Company in creating work plans that seek to maximize reliability, safety, and customer benefit within the context of the Company's financial position. The forecast that is generated as a result of these activities is based on data from the past and present along with analysis of trends to provide an expected future picture to rely upon for planning.

I&M is comprised of four business units: (1) Fossil, Hydro & Solar Generation, (2) Nuclear Generation, (3) Transmission, and (4) Utility Operations. The O&M and capital forecasts prepared by each business unit are based on work plans that use business objectives to prioritize work activities. In addition to the functional Business Unit forecasts, I&M also incorporates the capital and O&M budgets and long range forecasts from AEP Service Corporation for corporate services including, but not limited to, information technology and shared services.

I&M's business units go through an extensive effort to identify a work plan consisting of a list of proposed capital projects for the future. Each business unit uses drivers specific to its area of the business to determine which projects to include and the timing by which the projects need to be completed. Some examples of common business drivers include environmental compliance, regulatory compliance (e.g. Nuclear Regulatory Commission or "NRC"), PJM compliance, public/employee safety, aging infrastructure, reliability improvements, and performance improvements.

Each business unit develops its O&M budget based on the costs necessary to maintain ongoing operations plus incremental O&M needs. Ongoing operations costs typically include labor, fringe benefits, fleet vehicles, insurance, consumable materials and chemicals, right of way maintenance, mandated fees, etc. and are largely non-discretionary within a given year. Each budget is prepared in accordance with Corporate Budgeting Guidelines, which include various assumptions and provide guidance for things such as labor escalation factors. Incremental O&M includes the cost associated with scheduled outages at major generating facilities and major inspection or maintenance programs within distribution and transmission. Once ongoing operations O&M has been approved, proposed business unit incremental needs are evaluated and prioritized by I&M management and the available resources are allocated in order of greatest operational and/or customer benefit.

AEP Service Corporation costs for items such as Information Technology (IT) and Shared Services are required to prepare strategic plans and financial forecasts which are presented to the Investment Review Committee (IRC) to obtain approval for capital and O&M allocations. I&M management participates in these discussions to provide input on the allocation of funds and the specific impact and benefits to I&M.

The Test Year (TY) level of Fossil Steam, Nuclear, Hydraulic and Other Generation O&M expenses are reasonable in aggregate as compared to actual expenses. O&M expenses for the Generation function (excluding account 501 fuel, 502 emissions control, and 509 allowances) are forecasted to decrease in relation to all five most recent calendar years (2014 through 2018) by -1.1% on average, not including any inflationary adjustments to historical costs. In addition, each category of TY O&M expense is reasonable in relation to actual expenses. The TY level of O&M expense in the forecast, combined with the adjustments proposed in this case, is accurate, reasonable and representative of I&M's cost of providing service. The TY levels are justified by the projected needs of the utility and are not excessive. I&M has demonstrated proactive management that has successfully allowed I&M to maintain O&M, in many cases, with minimal or no increase over the past several years while at the same time absorbing inflationary impacts.

The overall level of forecasted capital expenditures during the Capital Forecast Period (January 1, 2019 through December 31, 2020) is reasonable compared to the last three years of actual capital expenditures. The average annual capital expenditure in 2019-2020 is forecasted to be $616 million compared to $585 million in 2016-2018, an estimated increase of 5%. Considering inflationary factors and specific capital programs taking place during the Capital Forecast Period, the overall amount is reasonable compared to historical actual expenditures. Moreover, the allocation of capital across the business units is consistent with I&M business unit work plans and accurately represents our capital investments during this time period. The TY level of capital investments, combined with the adjustments proposed in this case, is reasonable, necessary and representative of I&M's cost of providing service. The Capital Forecast Period levels are justified by the projected needs of the utility and are not excessive.

I&M engages in economic development in the communities we serve because of the importance of helping those communities grow and prosper. I&M's economic development efforts, in collaboration with our 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. Economic development also benefits I&M customers through the creation of new jobs for the citizens of our communities, opportunities for expansions of our current business, and an increased tax base for our communities. Additionally, the increased load that is a direct result of the capital investment benefits all I&M customers by spreading the fixed costs that are necessary to maintain the electric system, ultimately lowering customer rates.

I&M has implemented the economic development programs that were included in the settlement agreement approved in Cause No. 44967. Any unallocated funds are not included in the revenue requirement presented in this case. I&M has reflected $137,500 in the TY revenue requirement to continue the third component of the Economic Impact Grant program after rates go into effect in this base rate case. These funds will allow I&M to continue to provide grants to eligible customers, including members of the Joint Municipal Group and 39 North Conservancy District, to support Qualifying Projects.

Despite I&M's efforts, there continue to be challenges to economic development in I&M's service area. To address these challenges, I&M is proposing two new economic development pilot programs in this case aimed to create significant value for our customers today and into the future.

The Apprenticeship and Training pilot program will assist eligible customers in providing established and credible apprenticeship and employee training programs. This program will aid in retaining existing customers in I&M's service area by providing an increased opportunity for companies to train their workforce on new technologies that will increase the efficiency of the current operations. Additionally, having a well-trained and skilled workforce will also provide a talent pool for companies expanding or seeking new opportunities in I&M's service area. Finally, the employees of companies that provide quality training programs and invest in their employees will also certainly benefit.

I&M's proposed Building Development pilot program will assist communities with the development of "spec" buildings in the I&M service area. In cooperation with the local unit of government, developer, and local economic development organization, I&M will be able to actively market new spec buildings developed as a result of this program to attract new businesses to the I&M service territory. The costs of these pilot programs are reasonable and necessary in order to make an impact on economic development in I&M's service territory.

These two economic development pilot programs will build on and complement existing state and local efforts. To be able attract new businesses and support existing businesses in being able to compete in an increasingly global economy it is essential that we invest in our most valuable resource – our people. In an increasingly global economy with changing technology and the need for new job skills, the Apprenticeship and Training pilot program is essential to be able to continue to retain and attract economic development opportunities. In addition to having a skilled workforce, it is also critically important that we equip the economic development teams in I&M's service area with an inventory of spec buildings to compete for business expansions or new businesses. Utilizing the proposed programs in this case to incentivize local governments and developers to invest in our communities will result in new jobs for our customers, increased investments in our local communities, and an expanded customer base to share in I&M's fixed costs.

I&M is proposing to continue the four customer assistance pilot programs agreed to in Cause No. 44967 through 2020 as currently defined through the collaborative process with stakeholders. I&M has included funding for the Energy Share, Low Income Weatherization and Neighbor to Neighbor programs to continue administering these programs in 2020 and beyond. The fourth program, the Low Income Arrearage Forgiveness pilot program, is expected to start enrolling customers until the fourth quarter of 2019. I&M will start the two-year pilot program when customer enrollments begin. I&M will allocate up to $500,000 over the two-year period as set forth in the settlement agreement. The funds associated with the Low Income Arrearage Forgiveness pilot program are not included in the revenue requirement presented in this case.

I&M is also proposing a new Income Qualified Safety & Health Pilot Program to address safety and health issues that prevent the completion of an income qualified energy audit and the installation of major energy savings measures. Through these audits, opportunities for major energy saving measure are identified and customers are made aware of how they can reduce their energy bills through improvements in their home.

The Company is proposing to consolidate its Green Power Rider (GPR) and Renewable Energy Option (REO) offerings 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 Renewable Energy Certificates (RECs). IM Green will allow all customers to purchase RECs as a percentage of their monthly kWh usage. 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 service agreement tailored to their specific business objectives and renewable energy needs. As a trusted energy advisor for our customers, we are driven, and uniquely positioned, to help our customers receive service according to their desires. The renewable landscape is very diverse and continues to change and it necessitates our service offerings changing as well. Our goal is to have the flexibility to meet as many of our customer needs as possible to not only support them, but to benefit all of our customers through a more efficient use of Company resources and generating incremental revenues to offset all customers' costs. The IM Green program provides flexible options for all customers and is structured in a way that supports competitive pricing and ensures that participation reduces the fuel costs reflected in the cost of service for all customers.

Prior to the implementation of the AMI (Advance Metering Infrastructure) meters, I&M will provide customers with a variety of opportunities to learn about the AMI technology and explain the benefits that AMI meters bring to customers. I&M will also provide directions on how customers can opt-out of receiving an AMI meter if they so choose. I&M has developed a thorough customer engagement and communication process for its AMI deployment, including utilizing the experience of I&M's sister companies during their AMI deployments. This process focuses on providing customers with the information necessary to understand the benefits they receive from AMI and make informed decisions about the use of AMI technology.

Company witness Isaacson discusses the many operational benefits of AMI deployment. An additional, significant benefit associated with the AMI technology after it is deployed is the opportunity for customers to have access to better information to make informed decisions about their energy consumption. AMI metering provides granular and timely data that I&M and its customers can use to better understand their energy usage and behaviors. The Customer Engagement Platform and Education Adjustment reflects the capital and O&M expenditures necessary to develop a multi-channel platform for residential and commercial customers to access insights specific to their home or business on energy usage, energy costs, and energy savings tips. The new customer engagement platform will transform the I&M customer experience by providing access to daily information on the amount of energy used and the costs for electric service. Having access to this information daily will provide customers with a much better ability to take action during the month to manage their energy costs. This is a very significant, positive change that will impact all customers, but particularly income qualified customers or fixed income customers that are managing within a monthly budget amount.

The customer engagement platform will give customers access to a variety of information about their energy usage, including billing history, current amount due, energy usage information, comparative analysis of energy usage and billings versus prior periods, modeled disaggregation of energy usage, and customized energy efficiency tips. Additionally, the customer will be able to set alerts and push notifications that will allow customers to receive notifications when their usage or costs exceeds pre-set amounts. This will allow customers to make better decisions about their electric consumption habits and better manage their monthly budgets.

From a customer perspective, the customer engagement platform is the vehicle that unlocks the power of having access to the data that AMI provides. The level of integration required to provide this platform is very extensive and requires a significant upfront investment to build out, but the benefit to customers of being able to use this information to make better decisions about their electric consumption habits and manage to their monthly budgets will be recognized for many years into the future.

I&M has leveraged AEP's experience as well as some recent pricing for components of the platform to develop its cost estimates for the program. The primary costs associated with this program are for building the integrations between I&M and AEPSC data and the technology firm data. Utilizing a combination of actual costs from similar integrations and market based cost estimates, the costs included in the adjustment are reasonable.

4. Nancy A. Heimberger, Financial Analyst Senior Staff in Corporate Planning and Budgeting American Electric Power Service Corporation. The forecasting process used in this proceeding is the same that was used in I&M's last basic rate case, Cause No. 44967. I&M's financial forecast contains the following major components: 1) load and demand forecast; 2) retail and firm wholesale revenue projections; 3) off-system sales (OSS) forecast; 4) generation forecast; 5) operation and maintenance (O&M) forecast; 6) construction expenditure forecast; and 7) financing plan.

The forecasted income statement as shown on Exhibit A-4 and balance sheet as shown on Exhibit A-2 were prepared in accordance with AEP's normal forecasting processes. The forecasted statement of cash flows as shown on Exhibit A-3 is a function of the items reflected in the forecasted balance sheet. Cash needs dictate the extent of debt and equity that is necessary to operate the business, given the timing of cash inflows and outflows. I&M's forecasted balance sheet fairly and reasonably reflects the account balances expected for the Company during the Test Year.

The major components of I&M's operating revenues are Indiana and Michigan retail sales, Federal Energy Regulatory Commission (FERC) wholesale sales, OSS, transmission revenues, and other operating revenues. The components of the Generation forecast are 1) Fuel; 2) Consumables; 3) Allowances; and 4) Purchased Power. The Test Year level of forecasted operating revenues, and fuel, consumables, allowances and purchased power expense, as adjusted by the Company, are accurate, reasonable, and representative of I&M's going forward cost of providing service.

Test Year O&M expenses, excluding energy costs, are based upon work plans for each of I&M's business units.

Transmission revenues and expenses are broken down in multiple categories. The first category is PJM Network Integration Transmission Service (NITS) revenues and expenses. The increase in this category is due to the growth in transmission investments made by I&M, other AEP affiliates, and other transmission owners within PJM. The second category, PJM transmission enhancement charges, primarily represents payments made by I&M to other transmission owners in PJM for the cost associated with regional transmission projects mandated by PJM. These costs are driven by PJM's objectives to increase reliability and modernize the grid and continue to grow significantly. Company witness Ali discusses this in more detail. The third category of transmission-related revenue and expenses is associated with transmission owner revenues and other transmission O&M expenses, the majority of which are the traditional embedded costs for I&M to operate and maintain its own transmission assets. This category is removed from the Company's cost of service, as discussed by Company witness Nollenberger.

The major components of depreciation and amortization expense included in the Test Year are depreciation expense, amortization of plant, and regulatory debits. The depreciation expense projection was developed, on a total Company basis, by applying the composite depreciation rates approved by this Commission, the Michigan Public Service Commission (MPSC), and FERC to projected monthly plant in service balances. I&M's plant in service is projected to increase by approximately $1.3 billion from 2018 through the Test Year, excluding ratemaking adjustments. Based upon this plant in service projection, and reflecting a full year of composite depreciation rates which were updated during 2018, the approximately $112 million increase in depreciation and amortization expense is reasonable. The Test Year level of depreciation and amortization expense, as adjusted by the Company, is accurate, reasonable, and representative of I&M's going forward cost of providing service.

The major components of taxes other than income taxes are revenue taxes, payroll taxes, and property taxes. The primary driver of the increase is associated with property taxes on the new utility plant in service. The major components of income taxes are federal income taxes, including both current and deferred taxes, state income taxes, and investment tax credits. The deferred income tax expense includes the amortization of the excess accumulated deferred federal income taxes (ADFIT) related to the TCJA. The decrease in income taxes is primarily due to lower taxable income and higher amortization of excess ADFIT, partially offset by other book/tax differences which are accounted for on a flow-through basis.

The forecast begins with actual account balances as of December 31, 2018 and adds forecasted capital expenditures for the Capital Forecast Period, which is defined as January 1, 2019 through December 31, 2020. Plant in service increased by $1,341 million during the Capital Forecast Period. Figure NAH-1 provides a summary of the functional projected activity during the entire Capital Forecast Period of January 1, 2019 through December 31, 2020. The Test Year plant in service balance, as adjusted by the Company, is reasonable, accurate, and representative of I&M's going forward cost of providing service.

This testimony supports the following adjustments in I&M Exhibit A-5 to I&M's Test Year net operating income, and in I&M Exhibit A-6 to I&M's Test Year rate base:

- Operating Revenue Adjustment No. OR-3 – To properly eliminate affiliated rent revenue and expense.
- Depreciation Expense and Accumulated Depreciation Adjustment No. DEP-1 – To reflect depreciation expense and accumulated depreciation using the depreciation rates currently approved by this Commission.
- Depreciation Expense and Accumulated Depreciation Adjustment No. DEP-2 – To reflect depreciation expense and accumulated depreciation using the depreciation rates as proposed.
- O&M Expense Adjustment No. O&M-2 –To remove value advertising expense.
- O&M Expense Adjustment No. O&M-3 – To remove lobbying expenses associated with the I&M State Office.
- O&M Expense Adjustment No. O&M-9 – To reclassify regulatory debits into various accounts.

The FAC basing point for the Test Year is 12.989 mills per kWh, as shown on Attachment NAH-8. The methodologies and assumptions used in the development of I&M's forecasted fuel costs and net energy requirements for the Test Year are the same methodology I&M used in Cause No 44967 and the methodology I&M traditionally uses in

Indiana fuel cost adjustment filings, a methodology the Commission has found to be reasonable.

5. David S. Isaacson, Director of Distribution Risk and Project Management Indiana Michigan Power Company. I&M serves approximately 468,000 customers in eastern and central Indiana in a service area that covers approximately 3,200 square miles and includes 118 cities and communities and 24 counties. I&M's Indiana service territory continues to experience operating challenges related to aging assets. Much of I&M's system was built in the 1960s and 1970s, when I&M's territory experienced growth. An increasing portion of assets are now reaching the end of their expected design lives. Vegetation remains a principal cause of outages in I&M's service territory. Trees are growing too close to wires on approximately 19% of I&M's overhead system. This is a significant improvement from I&M's last rate case, but substantial vegetation management must continue to further reduce tree-related outages.

I&M strives to provide customers the best reliability it can with existing resources and system conditions. I&M is making substantial investments in its distribution system through its Distribution Management Plan, and this has resulted in reliability improvement – meaning reliability has been better than it would have been without this substantial investment. I&M also recognizes its system challenges, especially related to vegetation and aging assets, which have resulted in I&M's overall reliability declining in recent years.

The purpose of I&M's Distribution Management Plan is to improve or maintain customer experience by improving reliability, addressing public safety, and modernizing the grid. I&M's Plan focuses on six key objectives: (1) Maintain and improve safety, (2) focus on the customer experience, (3) address reliability, resiliency, and aging infrastructure, (4) create an enabling platform, (5) improve data availability and use (both internally and externally), and (6) maintain flexibility. I&M developed the Plan by focusing on several inputs to determine the programs and projects that were most needed and would bring the most value for I&M's customers. The cost estimates for the programs in the Distribution Management Plan are developed using the same parametric cost analysis I&M uses for all distribution work. The Plan involves the following programs:

- Vegetation Management – I&M's vegetation management program involves moving away from a reactive approach to managing vegetation (trees, brush, and vines) to a systematic, cycle-based approach. Vegetation management remains the single greatest investment I&M can make to improve reliability.

- Asset Renewal and Reliability – I&M's Asset Renewal and Reliability Programs are a suite of programs developed to replace aging infrastructure and make the distribution system more resilient. I&M's asset renewal and reliability programs allow I&M to systematically and proactively address these risks to reliability, resiliency, and safety. Without these programs I&M would experience more asset failures and the quality of service to customers would unnecessarily suffer.

- Major Projects – Each year, I&M completes various distribution projects, termed "major projects," to address capacity and contingency capacity constraints (i.e., the ability to serve customers from another location, thereby reducing the length of an outage), to improve outage recovery, to replace or upgrade aging or obsolete station equipment, to implement supervisory control and data acquisition (SCADA), and to perform voltage conversions of select stations and distribution circuits.

- Risk Mitigation Programs – I&M has developed the risk mitigation programs to improve public safety through inspections of poles and other equipment. The risk mitigation programs are intended to identify and remediate assets that, due to age or condition, present a potential safety risk to the public or employees

- Grid Modernization Projects – I&M grid modernization projects are designed to utilize technology to improve system reliability and functionality and enhance the service customers receive. These projects include I&M's AMI deployment and installation of other smart distribution technologies such as network monitoring and distribution automation. I&M grid modernization projects will improve system reliability, improve safety, and increase customer satisfaction.

As noted above, I&M will be deploying AMI across its Indiana service territory over a three-year period from 2020 through 2022. AMI is a necessary investment at this time because 35% of the AMR meters deployed in I&M's Indiana service territory will reach the end of their design life by the start of the proposed AMI deployment. Rather than a patchwork AMI deployment to replace AMR meters as they reach the end of their design lives, it is prudent to build out the entire AMI system in a single deployment. Also, AMI provides visibility into I&M's distribution grid and allows I&M to manage its system better from an operational perspective. Deploying AMI will lead to numerous operational benefits that will allow I&M to improve its service to customers, including improved reliability, improved public and employee safety, reduced tampering and theft, improved meter accuracy, and remote reconnection. I&M's forecasted AMI deployment costs are capital investment of approximately $10.8 million in 2020, $40.6 million in 2021, and $38.8 million in 2022, plus O&M expenses of $0.3 million in 2020, $1.3 million in 2021, and $1.2 million in 2022.

For overall distribution capital investment included in I&M's Capital Forecast Period in this proceeding, I&M has reviewed its distribution system in order to determine the level of work that needs to be completed, including I&M's Distribution Management Plan, in order to maintain the integrity of I&M's system and provide safe and reliable service. Projects are based on sound engineering plans, and I&M's cost estimates are derived from Company experience and proven, effective methods. I&M forecasts $479.9 million of total distribution capital expenditures in 2019-2020. These expenditures are primarily related to the Distribution Management Plan discussed above, and also include costs for customer Service and city and state requirements.

Additionally, I&M forecasts distribution O&M expense of $76.3 million in the 2020 Test Year (as compared to $81.4 million in the 2018 historical period). These O&M expenses relate to ongoing O&M, including expenses such as labor, fleet vehicles, insurance, and consumable materials and chemicals; vegetation management O&M; and Major Storm O&M. For Major Storm O&M, it is reasonable to continue I&M's Major Storm

Reserve because I&M's Major Storm expense is variable from year to year, and the Reserve allows I&M to recover the true costs of a major storm without the need to use other funds already allocated to other necessary distribution O&M activities.

6. Q. Shane Lies, Site Vice President at the Cook Plant Indiana Michigan Power Company. The Cook Plant is a two-unit nuclear power plant located along the eastern shore of Lake Michigan in Bridgman, Michigan. Both units are pressurized water reactors with four-loop Westinghouse nuclear steam supply systems. The combined nominally-rated net electrical output for both units is 2278 megawatts (MWe). Unit 1 is currently licensed to operate until 2034, and Unit 2 until 2037. The Cook Plant is operated by I&M's Nuclear Generation Group (NGG), which consists of approximately 1200 full time I&M employees.

As a result of the well-planned, cost effective investment in and maintenance of the Cook Plant, it is in good condition, and necessary for I&M's provision of safe, reliable electric service to its customers. Cook's overall performance is strong. Unit 1 has operated continuously for its last two consecutive 18-month refueling cycles, and Unit 2 continuously operated during its previous cycle and is currently on a continuous run of more than 325 days. For regulatory performance, the current ratings in the Nuclear Regulatory Commission (NRC)'s Revised Reactor Oversight Process are all green (the highest achievable level) for both Unit 1 and Unit 2.

Cook Plant O&M expenses include base operating expenditures and non-outage equipment reliability expenditures. Included in the base operating expenditures are refueling outage amortizations, which can have a significant impact on O&M expenditures in any given year depending on the refueling outage cycle. The NGG is constantly evaluating the future needs of Cook to ensure that it continues to operate safely, reliably, efficiently, and in compliance with all regulatory requirements. The projected Cook O&M expense for the 2020 Test Year is $252.5 million; including allocated administrative and general expenses, this Test Year O&M level is approximately 1% lower than the 2018 historical level.

The forecasted capital expenditures for the Cook Plant during the Capital Forecast Period are approximately $281 million. This level of capital investment represents a reasonable level of spending needed to ensure the safe and reliable operation of the Cook Plant. Similar to O&M expenses, proposed capital expenditures undergo an extensive development and refinement process. If and when capital investments are made is based on a combination of factors, including whether the investment is needed to fulfill regulatory or safety requirements, the urgency of the need, and economic benefit. Cook's forecasted capital investment can be divided into the following categories:

- Life Cycle Management (LCM) Project – The LCM Project is a comprehensive effort to identify and undertake Cook Plant capital investments needed to ensure the units can operate through the end of their license extensions. In Cause No. 44182, the Commission approved the LCM Project and authorized I&M timely recovery of LCM costs through I&M's LCM Rider.

- Preventative & Corrective Maintenance – The expenditures in this category include necessary expenditures for maintaining and replacing Cook systems and equipment.

- Equipment Reliability – Expenditures in the Equipment Reliability category include pump and valve replacements, installation of monitoring and detection systems, and switchyard upgrades, to name a few. A substantial project within this category is the Unit 1 Main Generator Stator Rewind. During the Main Generator Rotor inspection conducted during the Unit 1 Cycle 28 refueling outage, the Main Generator Stator failed testing, and the AEP generator repair team determined that a rewind of the generator stator would be the most cost-effective repair. Another substantial project is the Unit 1 and Unit 2 Reactor Controls and Instrumentation Upgrade, which involves installation of a new fault-tolerant control platform that will increase system availability and support event-free operation.

- Regulatory Compliance – The majority of the Capital Forecast Period expenditures in the Regulatory Compliance category are related to Fukushima modifications and the Baffle Bolt and Up-Flow Conversion Projects. The Fukushima modifications are based on NRC regulatory requirements issued after the 2011 earthquake and tsunami that severely damaged the Fukushima Dai-ichi Nuclear Power Station in Japan. The Cook Plant has already completed many Fukushima-related modifications and will complete the project during the Capital Forecast Period. The Baffle Bolt and Up-Flow Conversion Project involves replacement of degraded “baffle bolts” within the baffle structure. Bolts found to be degraded in inspections must be replaced. In addition to conducting these inspections and bolt replacements, Cook has also implemented the Up-Flow Conversion Project to convert the units to up-flow configurations that will relieve future stress on the baffle bolts. Performing the up-flow conversion along with the installation of the MBP resolves the issue of baffle bolt failure and minimizes the consequences of any future bolt failures.

- License Renewal – These capital expenditures relate to those activities that are necessary to support Cook’s renewed operating licenses, including License Renewal Commitments made to the NRC.

- Other – These investments are capital projects that are not captured in the categories discussed above, such as Rod Cluster Control Assembly replacements; fiber optics installation; simulator upgrades; self-contained breathing apparatus bottle replacements; and general plant improvements.

Additionally, I&M is including an adjustment in this proceeding relating to Cook’s Clear Water Act Section 316(b) project. The 316(b) Rule requires individual facilities, including Cook, to evaluate the mortality-related impacts of their cooling water intake system on large and small aquatic organisms. In Michigan, the 316(b) Rule is regulated by the Michigan Department of Environmental Quality (MDEQ). Initially, prior to undertaking in-depth studies, Cook was concerned that the 316(b) Rule could require Cook to install a costly closed-cycle cooling system (i.e., cooling tower) retrofit. However, through detailed studies and testing, Cook has been able to support an application to the MDEQ that calls for no additional retrofits or actions by Cook to comply with the 316(b) Rule. As of December 31, 2018 approximately $10.7 million has been spent on the 316(b) Project. The Company requests amortization and recovery of these costs in this proceeding as further discussed by Company witness Williamson. Incurring these expenses was necessary for Cook to comply with the 316(b) Rule and resulted in a well informed and thoroughly reviewed recommendation to the MDEQ.

7. Timothy C. Kerns, Managing Director – Generating Assets for Indiana Michigan Power Company. I&M's non-nuclear generating fleet consists of the coal-fired Rockport Plant, six run-of-river hydro facilities, and four Universal Solar generating sites. I&M's Rockport Plant is located in Rockport, Indiana and consists of two similar coal fired generating units fired with pulverized coal. The nominal net generating capacity of Rockport Unit 1 is 1320 MW, and the nominal net generating capacity of Rockport Unit 2 is 1300 MW. I&M is directly entitled to 50% of the output of both Units; in addition, I&M affiliate AEP Generating Company is entitled to 50% of the output of both Units, and I&M purchases 70% of AEG's entitlement under a Unit Power Agreement (UPA) between I&M and AEG. Therefore, I&M is entitled to 85% of the total output of the Rockport Plant.

In addition, I&M's six run-of-river Hydro units are power stations situated along a river that utilize the river's flow for generation of power without materially altering the normal course of the river. These facilities combine for a total of 22.4 megawatts (MW) of installed capacity and consistently produce, on average, approximately 100,000 MWH of emission-free renewable energy annually. With a proper maintenance schedule, these facilities will be viable generating assets for many more years. I&M also has four Universal Solar facilities. Together, I&M's Universal Solar generating units have an installed capacity of 14.7 MW and provide another renewable energy resource to I&M's generation portfolio

Capital investment in I&M's non-nuclear generating fleet is based on work plans developed by the Company and vetted through multiple steps. I&M staff work collaboratively with AEPSC's Environmental, Engineering, and Project Management teams to evaluate the needs of each generating unit to maintain reliability, safety, environmental compliance, and other unit performance parameters. Non-nuclear generation capital expenditures during the Capital Forecast Period are approximately $156 million. This includes approximately $140.0 million in Major Projects and $16.1 million in Other Capital Investment. Major Projects are defined as non-nuclear capital investments greater than $1 million. The Other Capital Investment category includes capital expenditures associated with multiple smaller projects that represent the type of continuous investment that is necessary to maintain the availability and reliability of the generating units.

Non-nuclear major projects during the Capital Forecast Period are the following:

- Rockport Unit 2 SCR – The Commission granted a Certificate of Public Convenience and Necessity (CPCN) for this project in Cause No. 44871.

- South Bend Solar Project (SBSP) – I&M will propose the SBSP for approval by the Commission in a separate Cause.

- Rockport Unit 1 Spare Low Pressure Turbine Rotor Upgrade – This project will involve an upgrade of a spare LP turbine rotor to support the previously updated steam path. Having spare LP rotors significantly reduces the length of extended outages in the event of unexpected rotor damage or failure.

- Rockport Plant CCR Compliance – In April 2015, the U.S. EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash, bottom ash, and Flue Gas Desulphurization (FGD) gypsum generated at coal-fired electric generating facilities. Rockport's compliance with the CCR rule will primarily consists of the discontinued use of the east bottom ash pond and inciting closure.

- Rockport Unit 1 SCR 1st Layer Catalyst Replacement – The first layer Unit 1 SCR catalyst replacement is required to maintain NOX removal effectiveness.

- Constantine Hydro Plant Trash Rake Intake – Due to the configuration of the Constantine Hydro Plant, waterborne debris collects on intake screens impeding water flow to the hydroelectric turbines. Installation of intake screens and an intake screen cleaner at the entrance of the head race canal will eliminate the need to removed debris from the intake screens manually.

- Rockport Unit 2 HP Turbine Replacement – This project involves rebuilding the Unit 2 High Pressure (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.

- Rockport Intermediate Pressure Turbine Steampath Upgrade – This project upgrades the spare Intermediate Pressure (IP) D1000 turbine steampath to the upgraded D8000+ design.

- Rockport Enhanced DSI – The Enhanced DSI project involves the relocation of the sodium bicarbonate injection points in order the increase the utilization and removal efficiency of the DSI systems on both generating units. Company witness Thomas explains the reasons why I&M is undertaking the Enhanced DSI project and supports the overall reasonableness of the project.

Forecasted non-nuclear generation O&M expense includes costs associated with the operation, maintenance, administration, and support of I&M's generating units. These costs exclude fuel but include labor, material and supplies, contractor services, consumables, allowances, and other miscellaneous expenses for I&M's generating facilities. As discussed by Company witness Lucas, I&M develops its O&M budget based on the costs that are necessary to maintain ongoing operations plus incremental O&M needs with a focus to optimize O&M costs whenever possible. Forecasted Test Year O&M for Fossil (Steam) Generation is $117.6 million (compared to $121.3 million in 2018); for Hydro it is $3.6 million (compared to $5.0 million in 2018); and for Solar it is $0.25 million (compared to $0.36 million in 2018).

Two adjustments were necessary to accurately portray the forecasted Test Year non-nuclear generation O&M expenses. First, O&M Adjustment-4 was made to the amount of consumables expense (fossil) associated with the commissioning of the SCR on Unit 2. The Unit 2 SCR goes into service in May 2020; O&M Adjustment-4 is an annualized increase for the Test Year. Second, Adjustment RB/O&M-2 was necessary to reflect increased O&M (including consumables) related to the Enhanced DSI project.

The consumables and allowance expense components of non-nuclear generation O&M is significant, variable, and largely outside I&M's control. Consumables and allowances costs vary in the same way that fuel costs vary with respect to generation levels, and Rockport's operation is largely dictated by PJM market prices. There is also variability in the price of the consumables that I&M purchases.

8. Kamran Ali, Managing Director of Transmission Planning American Electric Power Service Corporation. I&M's transmission system is a highly networked grid comprising approximately 4,900 circuit miles of transmission lines ranging from 34.5 kilovolt (kV) to 765 kV in the I&M system, 4,100 of which are within Indiana. I&M's transmission system is part of the PJM regional transmission organization (RTO) and delivers electricity from generation sources to the retail and wholesale consumers served by I&M. I&M maintains its transmission facilities consistent with AEP standards that are based on industry standards and good utility practices, and the system is compliant with all federal and regional reliability standards. I&M also must address the challenges of aging infrastructure, the need to modernize transmission facilities, regulatory compliance requirements, and adapt to a changing generation portfolio. I&M expects that the transmission system will continue to evolve and change through technological advancements such as the adoption of electric vehicles, integration of renewable resources, retirement of fossil fuel based generation, and the implementation of new customer programs. As I&M's transmission infrastructure continues to age, the risk of failure for any given asset increases. I&M and AEP are implementing solutions to address these needs on the system and develop transmission projects based on several factors, including the performance and condition of each asset and the risk that the failure of each poses to the system and connected customers.

I&M's transmission system is part of the AEP eastern transmission system, which consists of the transmission facilities of ten AEP operating or transmission companies including I&M and AEP Indiana Michigan Transmission Company. Planning and operation of the system is integrated through the coordinated efforts of the AEP Transmission Department, a business unit of AEPSC, and PJM. I&M has input into the RTO planning process through AEP Transmission, but the costs allocated to I&M for the grid infrastructure investment in PJM outside I&M's service territory are not within I&M's direct control.

I&M participates in PJM as a Generator, a Load Serving Entity (LSE), and a Transmission Owner (TO). There are various charges and credits that the Company experiences resulting from each role. As an LSE, I&M is charged for costs associated with the functional operation of the transmission system, management of the PJM markets, and general administration of the RTO, irrespective of whether it owns the facilities that are being used. I&M pays to use the PJM transmission system, including its own assets, through charges that are based upon I&M's demand on the system. The costs include charges for I&M's purchase of Network Integration Transmission Service (NITS) under the PJM Open Access Transmission Tariff (OATT) to serve its retail customers. I&M also may incur NITS costs due to projects constructed by other transmission owners within the AEP Zone, and for Transmission Enhancement Charges for projects constructed by other transmission owners outside of the AEP Zone. PJM compensates I&M as a TO for owning and operating transmission assets. I&M incurs costs and offsetting revenues in accordance with the FERC-approved PJM OATT and Operating Agreement, which change from time to time. I&M also incurs expenses and receives credits from PJM for other activities associated with I&M's role as a Generator and LSE. Those non-NITS charges and credits include net transmission congestion charges and other ancillary services.

AEP Transmission participates on I&M's behalf in the PJM planning process, which is guided by PJM, North American Electric Reliability Corporation (NERC), ReliabilityFirst Corporation (RFC) and AEP planning criteria. The process results in three different categories of projects: Baseline Upgrades, Network Upgrades and Supplemental Upgrades (also called "Owner Projects").

Baseline Upgrades respond to needs that are a result of a criteria violation and include transmission expansions or enhancements that are required to achieve compliance with PJM's system reliability, operational performance, or market efficiency requirements, as well as those necessary to meet Transmission Owners' local transmission planning criteria. The cost of Baseline Upgrades is allocated to the benefitting zones based on voltage and project type.

Network Upgrades result from transmission customer requests for generator interconnection, merchant transmission additions, and long-term transmission service. Customers that cause the need for Network Upgrades are responsible for the costs of those projects.

Owner Projects are needed for many reasons, including regulatory requirements, modernization and hardening of the grid, replacement of failed equipment, proactive replacement of deteriorating assets prior to failure and improved operational efficiency and performance. I&M evaluates and selects Owner Projects following an established and detailed set of AEP Guidelines for Transmission Owner Identified Needs. The guidelines ensure that all AEP-affiliated transmission owners are applying consistent criteria in evaluations, while each Transmission Owner ultimately determines the mix of Owner Projects needed to maintain the reliability of their transmission grid within the AEP Zone. The need for Owner Projects is driven by, among other things, equipment condition, performance, and risk; operational flexibility and efficiency; infrastructure resilience; and customer service. The costs of Owner Projects are allocated to the transmission zone in which they are built. Many of the drivers of Owner Projects, including regulatory requirements, interconnection requests, asset performance, and the need for modernization of protection and control systems, are outside of I&M's control.

PJM coordinates a stakeholder process to review and provide input regarding all projects affecting the topology of the grid, whether PJM identified or Transmission Owner identified. Owner Projects are subject to multiple rounds of review and detailed project information, including alternative solutions, is provided to stakeholders. FERC also evaluates the prudence of transmission investment through AEP's annual transmission formula rate filings, which include protocols for the review of both the annual projection and true up of the AEP formula rates.

AEP, I&M, and other affiliates with projected transmission investment over the forecasted period internally develop forecasted PJM charges. Company witness Heimberger details that methodology which, at a high level, models projected necessary capital investment and required O&M to develop an estimated revenue requirement for I&M's projected transmission in service. The forecasted amount to be allocated to I&M through its role as an LSE is determined through an analysis of historical and forecasted transmission system usage.

I&M projects that its total PJM costs will increase over the forecast period from 2019 through 2023, including in the 2020 Test Year. The increase in the Company's PJM costs is primarily driven by PJM NITS costs. The forecasted increase in NITS charges is being driven by necessary investment in transmission infrastructure, both within I&M's service territory and throughout the remainder of the AEP Zone. NITS costs are billed to I&M consistent with FERC-approved tariffs, the PJM OATT and AEP's Transmission Agreement. I&M recovers NITS costs through the PJM Rider. I&M also may incur non-NITS costs associated with multi-zonal transmission projects, which benefit more than one PJM zone and whose costs are shared over the larger PJM footprint as determined by PJM.

The forecasted costs to be recovered through the OSS/PJM Rider are (1) collectively and potentially significant; (2) potentially variable or volatile; and (3) largely outside the utility's control. Both NITS and non-NITS costs are significant. The costs are also potentially variable or volatile, as the transmission capital additions completed by I&M and other transmission owners in the AEP Zone fluctuate year over year. Baseline Upgrades are included in the NITS rate if they are 100 percent allocated to the AEP Zone, which further contributes to the volatility of NITS costs. The costs recovered through the PJM Cost Rider are also largely outside of I&M's control and are driven by external factors.

NITS costs are reasonable and a necessary cost to maintain the reliability of the transmission grid and ensure equal access by all users of the transmission system. The costs that the Company forecasts will be recovered through the OSS/PJM Rider are also consistent with the costs currently recovered through the OSS/PJM Rider, as Company witness Williamson discusses. I&M's OSS/PJM Rider remains a reasonable process for the recovery of I&M's portion of the total NITS costs for the AEP Zone.

9. Jason A. Cash, Senior Staff Accountant in Accounting Policy and Research American Electric Power Service Corporation. I&M's current depreciation rates are based on the settlement agreement approved in Cause No. 44967. Based on results of the recent depreciation study, the Company recommends an overall increase in I&M's depreciation accrual rates, to be made effective upon implementation of new base rates. The recommended depreciation accrual rates would increase annual depreciation expense by approximately $32.2 million on an Indiana jurisdictional basis.

All of the property included in the Depreciation Study Report was considered on a group plan. Under the group plan, depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group instead of individual items of property. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. In this study, the plant groups consisted of the individual primary plant accounts for Production, Transmission, Distribution, and General Plant property. The depreciation rates were calculated by the Average Remaining Life Method, which is the same method that was used to calculate I&M's current depreciation rates. The Average Remaining Life Method recovers the original cost of the plant (adjusted for net salvage) less accumulated depreciation over the average remaining life of the plant.

Net salvage for each property group was determined based on actual historical experience for Production, Transmission, Distribution, and General Plant accounts. In addition, Production Plant included terminal retirement net salvage amounts for Steam and Hydraulic Production Plant. To determine terminal net salvage for Steam Production Plant, I&M commissioned the independent industrial service company, Brandenburg, to update the conceptual dismantling cost estimate for the Rockport Plant. For I&M's hydraulic production plants, the depreciation study used the conceptual dismantling cost estimates that are reflected in I&M's current depreciation rates. The recommended depreciation rates include the estimated final removal cost and expected terminal net salvage amounts specific to each of the Company's steam and hydraulic generating stations at their estimated retirement dates.

The Settlement Agreement approved in Cause No. 44967, reflected a depreciation rate that assumed an average remaining life of 11.46 years for Account 370, Meters. The current depreciation study reflects the Company's decision to replace its current meters with new Advanced Metering Infrastructure (AMI) meters over the next three years (2020-2022). In preparation of the meter replacement, the Company is proposing in this case to establish a depreciation rate for Account 370 that would allow for any undepreciated balance related to the current meters to be recovered over the life of the newly installed AMI meter, which is estimated to be approximately 15 years. This proposal is consistent with standard retirement accounting policies and procedures.

Recovery of the remaining value of a generating station or Transmission, Distribution and General property is normal utility ratemaking practice and this practice follows FERC Electric Plant Instruction No. 10 "Additions and Retirements of Electric Plant".

In Cause No. 44871, the Commission granted I&M a certificate of public convenience and necessity (CPCN) to install SCR technology on Rockport Unit 2. In that proceeding, the Commission also granted I&M's request for a ten-year depreciation rate for the Rockport Unit 2 SCR, or 10.00%. The Unit 2 SCR is expected to be placed in service in May 2020. Use of a 10.00% depreciation rate does not allow for the Unit 2 SCR to be fully depreciated when the Rockport Unit 2 lease expires and the Unit 2 assets are retired in 2022 or when the Rockport Plant retires in 2028. In order to reduce the possibility that an undepreciated balance will exist at the time that the Rockport Plant is retired, the Company proposes establishing a 12.00% depreciation rate in this Cause in order to recover the investment in the Unit 2 SCR plus net salvage over the remaining life of Rockport Unit 1, or 2028. In addition, the Company respectfully requests that the Commission approve any remaining net plant associated with the Unit 2 SCR to be recovered through Rockport Unit 1 depreciation when the Rockport Unit 2 lease expires and the Unit 2 assets are retired.

Depreciating the Unit 2 SCR over the remaining life of Rockport Unit 1 remains consistent with the depreciation treatment that was used for I&M's retired Tanner Creek units. It is also consistent with the depreciation treatment of the Rockport Unit 2 DSI that was approved in I&M's last rate case (i.e. if the Rockport Unit 2 lease is not renewed and the Rockport Unit 2 depreciable plant is retired from the Company's books, any remaining net plant associated with the Rockport Unit 2 DSI will be recovered through Rockport Unit 1 depreciation).

The Company will be filing a separate case that is specific to a proposed 20 MW solar facility in South Bend, Indiana. I&M is requesting that a depreciation rate be established for the project during this rate case because the project (if approved) is forecasted to be placed in service during the Test Year. The Company proposes initially using a 3.40% depreciation rate for the South Bend Solar project which is based on Company estimates of a 30 year useful life and also includes a component for terminal net salvage.

In addition to the Company's electric utility plant in service and accumulated depreciation on the books at December 31, 2018, the depreciation study includes an adjustment for the 2019 forecasted additions to plant in service at Rockport, Cook, and the Company's hydraulic generating stations to reflect a forward looking test period for the Company's steam, nuclear and hydraulic production plant investment. The depreciation study also includes a calculation to estimate a corresponding adjustment to accumulated depreciation for all of production plant that reflects an additional year of depreciation accrued through 2019. Including the forecasted additions and accumulated depreciation will ensure that more accurate depreciation rates are established for each generating station when rates become effective in 2020. Establishing depreciation rates in this manner better supports the full depreciation of such assets and better aligns customer rates with the remaining service life of each generating station while reducing the extent to which the costs will need to be recovered through rates after the assets are no longer in service.

The composite depreciation rate for Steam Production Plant increased slightly from 7.52% to 7.77% mainly due to a $21.7 million increase in the depreciable plant in service balance since the 2016 depreciation study.

The composite rate for Nuclear Production Plant increased from 3.22% to 4.13% mainly due to a $298.7 million increase in the depreciable plant in service balance since the 2016 depreciation study. The increase in depreciable nuclear plant in service since 2016 is mostly due to the LCM Project, which is discussed in detail by Company witnesses Thomas and Lies.

The composite rate for Hydraulic Production Plant increased from 2.30% to 2.72% due a $3.3 million increase in the depreciable plant in service balance since the 2016 depreciation study.

The composite depreciation rate for Other Production Plant increased slightly from 5.26% to 5.29% due to a small increase in the depreciable plant in service balance since the 2016 depreciation study.

The depreciation rate for Transmission Plant increased from 1.95% to 2.48% due to increases in the net salvage ratio for five accounts (Accounts 353, 354, 355, 356 and 358) and decreases in the average service life for three accounts (Accounts 352, 353, and 355). The depreciation rate increase was partially offset by an increase in the average service life for Account 356.

The depreciation rate for Distribution Plant increased slightly from 3.53% to 3.54% due to increases in the net salvage ratio for six accounts (Accounts 361, 362, 364, 365, 369 and 373), decreases in the average service life of two accounts (Accounts 361 and 362), and updating the depreciation rate that was calculated for Account 370. The increase was offset by increases in the average service life for eight accounts (Accounts 364, 365, 366, 367, 368, 369, 371, and 373).

The depreciation rate for General Plant increased from 3.46% to 3.59% due to increases in the net salvage ratio for three accounts (Accounts 390, 391, and 398). The rate increase was partially offset by an increase in the average service life for Account 390.

10. Aaron L. Hill, Director of Trusts and Investments American Electric Power Service Corporation (AEPSC): The purpose of the external 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, and restoration of the plant site. Making regular, periodic contributions to fund the decommissioning trust provides funds for the future cost of decommissioning the nuclear power plant by customers who are receiving the benefits of its electric power generation during the plant's useful life.

Unit 1 of the Cook Nuclear Plant is scheduled to be retired in 2034, and Unit 2 of the plant is scheduled to be retired in 2037. The current funding rate of $2.0 million annually should be increased to $10.0 million. Increasing the current funding level will increase the probability of successfully decommissioning the plant and mitigates shortfall risks associated with investment return, cost inflation, future events, and other assumptions that cannot be predicted with certainty.

As in previous cases, a Monte Carlo simulation was used to project both the trust fund and decommissioning costs. Monte Carlo simulation is a useful method to create a set of possible results for situations in which the inputs are uncertain. The modeling shows that at the proposed $10 million funding level, the probability of having sufficient funds is approximately 90%. The increased funding will also put the probability of successful funding of the decommissioning liability on better parity with Michigan retail customers and reduce the risk that Indiana retail customers will have to significantly increase annual funding late in the Cook Plant's life or continue contributions after the Cook Plant retires.

We are now only 15 years away from the first unit shutting down in 2034. We are only five years away from beginning to de-risk the nuclear decommissioning asset allocation, which is scheduled to begin 10 years prior to the start of decommissioning. These are relatively short time horizons to recover from losses and post gains. It is critical that as we get closer to the plant's shutdown, the probability of successfully decommissioning the plant increases accordingly, so that at shutdown, the probability of success is 100% and the liability is fully funded.

Although I&M certainly intends to operate the plant until its planned retirement there still remains the possibility that the plant may be shut down prior to the expiration of the operating license. This possibility would have the effect of not allowing the decommissioning funds to grow for as long as is currently planned, and would increase the probability that the decommissioning funds available may be insufficient to pay for the decommissioning expenses.

This is why it is important to increase the funding level now, when there is time to gradually protect against a future short fall, rather than suffer one prior to decommissioning, with little time to recover.

The funding for the Pre-April 7, 1983 spent nuclear fuel disposal should remain suspended for the time being. I&M will continue to monitor the level of funding for nuclear decommissioning and for Pre-April 7, 1983 spent nuclear fuel disposal. I&M will continue to report to the Commission every three years on the adequacy of the existing provision, however, and it may recommend adjusting the level of decommissioning fund contributions needed in the future. This testimony and attachments serve as the report for the current three-year cycle.

The investment guidelines for the Pre-April 7, 1983 spent nuclear fuel disposal should be expanded so the balance of Indiana jurisdictional pre-April 7, 1983 assets that exceed the Indiana jurisdictional liability by a factor of 1.05 or more, should be permitted to be invested pursuant to the investment guidelines currently in place for the Indiana Nuclear Decommissioning Trust. This would allow for increased diversification in the Spent Nuclear Fuel trust portfolio and is expected to extend the life of the trust surplus compared to the current strategy. The downside outcomes with the expanded guidelines are expected to be in line with the current strategy, while the surplus could experience an increase in the best performing cases.

Finally, consistent with the Orders in IURC Cause Nos. 44967 and 44075, I&M seeks to continue the inclusion of Prepaid Pensions in I&M's rate base. The order in Cause No. 44075 stated that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards, the prepaid pension asset reduced the pension cost reflected in the revenue requirement in the case, preserves the integrity of the pension fund, and should be included in rate base. The value of the prepaid pension asset is projected to be $89,244,007 on December 31, 2020, I&M's Test Year end and its continued inclusion in I&M's rate base is appropriate.

11. Roderick W. Knight, Decommissioning Manager TLG Services, Inc. (TLG). TLG performed a site-specific cost estimate for the decommissioning of the D. C. Cook Nuclear Power Plant. The study was required to determine whether the Company is adequately providing for the eventual decommissioning of the Cook Plant. The 2019 Study incorporates the most current information available to date. The costs developed for the 2019 Study provide a realistic estimate of the actual future costs and is reliable for I&M's financial planning purposes.

The total estimated cost for the decommissioning is $2,032 million in 2018 dollars. This means that although a task may not actually occur until after final shutdown, its cost is estimated as if it occurred in 2018. This amount reflects removal of the Cook Plant using the DECON scenario, which is the scenario the Commission has adopted as a basis for funding nuclear plant decommissioning in every case in which a TLG witness has testified. The estimated cost includes costs to remove all radioactive materials from the site which exceed the release criteria, terminate the NRC operating licenses, remove all structures above the three foot below grade elevation and backfill all below grade voids to the surface elevation and transfer all spent fuel from all the spent fuel pool to the on-site Independent Spent Fuel Storage Installation (ISFSI). Costs have also been determined to operate the ISFSI on an annual basis and to decommission and restore the site on an as yet to be determined date.

12. Michael N. Kelly, Manager of Taxes of Tax Accounting and Regulatory Support American Electric Power Service Corporation. Mr. Kelly's testimony describes the methodology used to develop the federal and state income tax expense for the Test Year. The methods used in this case are consistent with prior rate filings. The Company's state and federal income tax expense has been properly recomputed to reflect the appropriate tax effects resulting from the various ratemaking adjustments supported in this case. The adjusted Test Year level of other tax expense is appropriate and necessary and reflects the proper amount of going-level expense. The Gross Revenue Conversion Factor calculated on Exhibit A-8 indicates the appropriate factor that should be applied to the income deficiency in order to determine the amount of incremental revenue needed to obtain the required level of operating income. Exhibit A-9 calculates the Company's effective federal income tax rate after taking into consideration permanent and flow-through timing differences, excess deferred federal income taxes, and deferred investment tax credit amortization.

13. Robert B. Hevert, Partner at ScottMadden, Inc. Mr. Hevert's analyses indicate that I&M's Cost of Equity currently is in the range of 10.00 percent to 10.75 percent. Based on the quantitative and qualitative analyses discussed throughout his Direct Testimony, it is his view that 10.50 percent is a reasonable estimate of I&M's Cost of Equity.

As to its 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 concludes that the Company's proposal is consistent with the capital structures that have been in place over several fiscal quarters at comparable operating utility companies. Given the consistency of its proposal with similarly situated utility companies, Mr. Hevert concludes that the Company's proposed capital structure is reasonable and appropriate. The Company's projected weighted average cost of long-term debt at the end of the test year, 4.54 percent, is reasonable and appropriate.

Because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. Mr. Hevert therefore relied on several widely accepted methods applied to a proxy group of comparable publicly-traded electric utility companies to develop his Return on Equity (ROE) recommendation: (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. Those analyses indicate the Company's Cost of Equity currently to be in the range of 10.00 percent to 10.75 percent. That range is corroborated by the Expected Earnings approach which is supported by recent FERC Orders.

Mr. Hevert's 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, he 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. Although those factors are very relevant to investors, their effect on the Company's Cost of Equity cannot be directly quantified. Therefore, Mr. Hevert 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. In light of those analyses, his recommended range is reasonable and appropriate.

As Mr. Hevert's testimony demonstrates, I&M's capital expenditure program is significant. Further, I&M's capital expenditure plan is significantly larger than its internally generated cash, likely placing downward pressure on its free cash flow and credit profile. Because the financial community recognizes the need for timely cost recovery for those capital expenditures, the Company's capital recovery mechanisms are important to continue to provide retained earnings as a funding source for the Company to mitigate equity capital market risk. Although the Company's recovery mechanisms may be credit supportive, they are not necessarily credit enhancing. Consequently, the Commission's decision in this proceeding will directly affect the Company's ability to fund capital investments with operating cash flows, and the financial community's view of its financial profile.

In developing his recommendation, Mr. Hevert recognized that the low and high ends of the range of results (set by the low end of the range of Constant Growth DCF model results, and the high end of the range of CAPM results, respectively) are not likely to be reasonable estimates of the Company's Cost of Equity. In large measure, that is the case because those results are far removed from the returns recently authorized in other jurisdictions and, in the case of DCF-based methods, fail to adequately reflect evolving capital market conditions. Because Risk Premium-based methods directly reflect measures of capital market risk, they are more likely than other approaches (such as the Constant Growth DCF method) to provide reliable estimates of the Cost of Equity during periods of market instability.

The United States Supreme Court established the guiding principles for establishing a fair return for capital in two cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* (*"Bluefield*"); and *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*"). The Court recognized that: (1) a regulated company cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated company will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of the same risk (the principle relating to the supply of capital). Indiana precedent provides similar guidance. Based on these standards, the ROE authorized in this proceeding should provide the Company with the opportunity to earn a fair and reasonable return, and enable efficient access to external capital under a variety of market conditions. To the extent the Company is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders should be disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables I&M to provide safe, reliable electric utility service while maintaining its financial integrity.

In very general terms, the Cost of Equity is the return investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return they *expect* is equal to, or greater than, the return they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities. The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid. Because equity investors bear that additional, “residual risk”, they require higher returns than debt holders. Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated based on market data and various financial models.

Estimating the Cost of Equity 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. 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. Therefore, the results of each ROE model must be assessed in the context of current and expected capital market conditions, and relative to other appropriate benchmarks. The models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. Therefore, it is important to assess the reasonableness of any financial model’s results in the context of observable market data. To the extent a given model’s assumptions are misaligned with such data, or its results inconsistent with basic financial principles, it is appropriate to consider whether other methods likely provide more meaningful and reliable results.

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. Federal monetary policy has had a significant, intentional effect on capital markets, dampening both interest rates and volatility. At issue is whether we reasonably can assume the market conditions created by those policies will stay in place over the long run. As a practical matter, the mean Constant Growth DCF results are well below a highly observable and relevant benchmark: the returns authorized for vertically integrated electric utilities. As such, considering multiple methods, including the CAPM approach, and the Bond Yield Plus Risk Premium model, is more appropriate in current market conditions. The Risk Premium methods estimate the additional compensation required by investors for taking on additional increments of risk. Because Risk Premium-based methods directly reflect measures of capital market risk, they are more likely than other approaches (such as the Constant Growth DCF method) to provide reliable estimates of the Cost of Equity during periods of market instability. As such, Mr. Hevert has given somewhat more weight to the Risk Premium-based methods in arriving at his ROE recommendation.

Other jurisdictions have recognized that the constant growth DCF model recently has failed to provide reliable ROE estimates sand other methods should be given meaningful weight in determining the ROE. In its November 15, 2018 *Order Directing Briefs*, FERC found that “in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE.” Quite simply, the constant growth DCF model’s underlying structure and assumptions are not compatible with the recent capital market and economic environment.

From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst, and the capital market environment in which the analyses were undertaken. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increased interest rates during the period in which the rates set in this proceeding will be in effect.

Because the application of financial models and interpretation of their results often is the subject of differences among analysts in regulatory proceedings, it is important to review and consider a variety of data points. That approach enables us to put in context both quantitative analyses and the associated recommendations. Further, because all models produce ranges of results, it is important to consider the type of information discussed above to determine where the Company's ROE falls within those ranges. Doing so supports Mr. Hevert's recommended range of 10.00 percent to 10.75 percent.

14. Franz D. Messner, Managing Director of Corporate Finance American Electric Power Service Corporation. I&M's projected overall weighted average cost of capital, inclusive of ratemaking adjustments, is 5.89% at the beginning of the Test Year (December 31, 2019), and 5.91% at the end of the Test Year (December 31, 2020). In both cases, the Company utilizes a 10.5% cost of equity supported by Company witness Hevert. The projected cost rates for long-term debt at the beginning of the Test Year (December 31, 2019) and at the end of the Test Year (December 31, 2020) (shown on pages 1 and 3 of Exhibit A-7) are 4.53% and 4.54% respectively. The Test Year capital structure and weighted average cost of capital are shown on I&M Exhibit A-7.

As part of the Settlement Agreement approved in Cause No. 44967, the cost of capital was adjusted to reflect refinancing of the $475 million in Series I Bonds and amortization of a make whole call premium over the life of the replacement debt. The net result of this refinancing, inclusive of make whole and issuance costs, is a lower cost of long-term debt associated with the $475 million.

Financing activity between the end of the historical period (December 31, 2018) and the end of the Test Year (December 31, 2020) includes the $25 million City of Lawrenceburg Series 2008 I Pollution Control Bonds which mature in October 2019 and the Company's intention to issue $300 million of new long-term debt in November 2019 to supplement the needs of its ongoing capital investment program.

Credit ratings are important to I&M. A higher credit rating results in lower cost of debt and better access to capital in times of financial volatility. I&M's senior unsecured ratings are A- at S&P and A3 at Moody's. On April 27, 2018, Moody's published an updated credit opinion in which they recognized the above average regulatory environments in the two state jurisdictions the Company operates in and that these states offer a suite of cost recovery mechanisms. A significant portion of the Company's credit rating is based on qualitative factors related to regulatory environment. Rating agencies closely follow regulatory outcomes for a utility. Consistent and appropriate regulatory treatment is a credit positive and supports the Company's credit ratings which in turn affords the Company better access to capital markets to better source capital at lower cost.

15. Jeffrey W. Lehman, Electric Transportation Program Manager for American Electric Power Service Corporation. I&M is proposing a three (3) year pilot program that consists of elements that each play an important role in the most effective manner to encourage plug-in electric vehicle adoption in a way that optimizes the overall electric system. Referred to as the "IM Plugged In" pilot, the program consists of four components:

1. Residential and small commercial plug-in electric vehicle charging.
2. Multi-unit dwelling plug-in electric vehicle charging.
3. Commercial and industrial fleet and workplace plug-in electric vehicle charging.
4. Electric vehicle education and technical development.

During 2018 the United States eclipsed the one million electric vehicle mark and by 2021 more than two million electric vehicles are expected to be on U.S. roads. The variety of plug-in electric vehicles now produced is an immense and much needed improvement. Whereas only three models within limited segments were available to purchase in 2011, there are now over 30 models available nationwide spanning all major vehicle segments, with 132 models projected to be available by 2022. The three fundamental factors facilitating these trends are: Governmental policy, Battery price declines, and Consumer preference and demand.

It is important that load from electric transportation be integrated into the grid in a manner that minimizes or eliminates additional system costs. This is generally accomplished by programs and rates that incent charging behavior to occur during off-peak times. When this happens, additional energy delivery sales occur without requiring additional fixed assets to be deployed within the system. This increases I&M's system utilization, and can provide downward price pressure on electricity rates for all I&M customers as the fixed system asset costs are spread over additional energy delivery sales. Incentivizing plug-in electric vehicles to charge off-peak not only benefits those who drive electric, but each and every I&M customer.

Conversely, if I&M does not engage to align incentives for customers to charge plug-in electric vehicles during off-peak times, the I&M system is highly likely to see greater peak capacity demands as default charging behavior coincides with existing system peaks, therefore reducing overall system utilization. This increase in peak capacity demand will require additional system investments and maintenance needs - from generation sources through distribution feeders and customer transformers.

It is important for I&M to have robust and scalable programs and outreach in place as plug-in electric vehicle adoption continues to accelerate.

To effectively integrate electric transportation into its electric system, I&M is proposing the IM Plugged In pilot program, which will provide value to customers who drive electric vehicles and enable their plug-in electric vehicle to charge during times when the distribution and bulk electric system is not coincident with or adjacent to peak demands.

Four primary benefits of electric transportation are:

Downward electricity rate pressure,
Reduction of transportation costs – fuel and maintenance,
Reduction of transportation emissions, and
Improved system information from program participation.

Plug-in electric vehicles are fundamentally different than other current electrical appliances in the following ways:

They are electrically large, power consuming devices,
They are electrically large, energy consuming devices, and
They are mobile.

Only locations with long vehicle dwell times present the opportunity to both meet customer needs and allow grid integration optimization that will result in downward rate pressure for all utility customers. Customer behavior studies have consistently found that when available, home charging comprises 80% or more of the transportation energy needs.

Similarly, fleets, which can be light, medium or heavy-duty vehicles in return-to-base operations for commercial, industrial, or municipal customers, discharge during use, and require charging during the evening and overnight period when they are returned to base. As such fleets can contribute to downward rate pressure and benefit to all utility customers in the same way as home charging.

Home charging is incredibly important to customers, and is a key opportunity for providing downward rate pressure and benefits to all customers. Under the current rate structure, residential and small commercial customers have no incentive to alter plug-in electric vehicle charging behavior to benefit all customers. I&M is proposing to provide customers with appropriate and aligned incentives by separately metering and billing the electricity consumption of a plug-in electric vehicle without requiring a new additional electrical service. This will require an additional AMI meter for each participant, and will allow the application of a new PEV tariff that provides electricity for the plug-in electric vehicle when energy costs are lower, i.e. during times when the system is underutilized – away from existing system peaks, which enables greater system utilization and drives benefit for all utility customers. Customers who choose to enroll in this program will receive a $500 rebate incentive at the time of enrollment. This helps to accelerate interest and offset the cost of electrical installation the customer may require. Without 240V electrical service at the parking location, a typical driver will not be able to charge their plug-in electric vehicle entirely away from the system peak. The rebate is very important to help minimize the cost barrier the electrical installation may pose.

Employers and fleet managers are becoming more interested in electrifying their fleets and helping their employees drive electric for many reasons, but are finding equipment and installation costs that did not exist with conventional combustion vehicles – these costs can become a barrier to choosing plug-in electric vehicle options, and may prevent these customers from adopting and operating plug-in electric vehicles that will provide benefit to all I&M customers. Multi-unit dwellings are also an important home application to address, as they have the same potential to provide benefits to all customers as residential and small commercial charging previously addressed. I&M is proposing to provide these two groups of customers either a $250 per-port rebate or an increased revenue credit calculation period, whichever the customer chooses. Both options help customers with charging infrastructure cost barriers, and allow for customer flexibility and choice. As more vehicles are deployed in these applications with the existing appropriate commercial rates, all I&M customers benefit.

The Company will engage in customer education technical development, awareness and outreach.

Interstate corridor charging describes plug-in electric vehicle fast-charging equipment installed along major highway corridors. Interstate corridor plug-in electric vehicle charging may be an important area for electric utilities, I&M included, to engage in to provide consumers with a solution faster than the market would otherwise address.

Indiana Michigan Power is evaluating company fleet vehicles for opportunities to reduce the Company's fleet transportation costs by driving plug-in electric vehicles. The Company is also analyzing our facilities to determine where to deploy workplace charging.

16. Tyler H. Ross, Director of Regulatory Accounting Services American Electric Power Service Corporation. This testimony presents and supports certain adjustments to net operating income and rate base for the 2020 forward-looking Test Year. The data relied on were acquired from numerous sources, including but not limited to I&M and AEPSC accounting records. This is the type of supportable data that has been found to be reliable and regularly used in I&M's business for this type of analysis. I&M's books and records follow the directives of the FERC Uniform System of Accounts (USOA). As a Securities and Exchange Commission (SEC) registrant company, I&M is also required to follow Generally Accepted Accounting Principles (GAAP), comply with specific SEC reporting requirements, and maintain controls over financial reporting in compliance with the Sarbanes Oxley Act of 2002.

This testimony supports the following adjustments in I&M Exhibit A-6 to I&M's Test Year rate base:

- Rate Base Adjustment No. 1 (RB-1) – Adjust various elements of rate base to reflect legacy test energy and pollution control investments related to Rockport Unit No. 1 on an Indiana jurisdictional ratemaking basis.
- Rate Base Adjustment No. 2 (RB-2) – Adjust various elements of rate base to remove Asset Retirement Obligations (ARO).
- Rate Base Adjustment No. 3 (RB-3) – Adjust various elements of rate base to remove the Smart Meter Pilot Project.
- Rate Base Adjustment No. 4 (RB-4) – Adjust various elements of rate base to reflect the following items on an Indiana jurisdictional ratemaking basis:
    - Rockport Unit 1 and Unit 2 DSI
    - Rockport Unit 1 SCR
    - Cook Plant LCM

- Rate Base Adjustment No. 5 (RB-5) – Adjust electric plant in service to reflect Rockport Unit 2 SCR on an Indiana jurisdictional ratemaking basis.
- Rate Base/Operation & Maintenance Adjustment No. 5 (RB/O&M-5) as included in I&M Exhibit A-5 and I&M Exhibit A-6 for the amortization of the December 31, 2018 Indiana major storm regulatory liability balance and the forecasted December 31, 2020 Indiana major storm regulatory liability balance.

These adjustments have been prepared in a manner consistent with accounting-related adjustments included in Cause No. 44967. If these adjustments were not made, I&M's Indiana jurisdictional rate base and I&M's base rates would be overstated. All of the adjustments described above related to changes in electric plant-in service and accumulated depreciation were provided to Company witness Heimberger for appropriate calculations of depreciation expense and accumulated depreciation in the forecasted test year. The rate base adjustments were also provided to Company witness Duncan for inclusion in her jurisdictional separation study.

In accordance with new accounting standards, I&M was initially required to reclassify its remaining deferred gain on sale/leaseback related to Rockport Plant Unit 2 from other noncurrent liabilities (Account 253) to equity. However, since the deferred gain has historically been provided to customers in rates, I&M instead reclassified the deferred gain on sale/leaseback to Account 254 (Regulatory Liability). This was done to assure that I&M's customers will continue to receive the benefit of this deferred gain. This balance sheet reclassification has no impact on I&M's cost of service in this proceeding, and I&M will continue to amortize the remaining deferred gain to Account 507.

Effective January 1, 2020, new FASB (Financial Accounting Standards Board) accounting standards require cloud service contract implementation costs be presented on balance sheets in the same manner as a prepayment for the associated hosting fees, which would change how I&M currently presents such costs. The FERC is currently reviewing this accounting change. Following the change in accounting for cloud computing implementation costs effective January 1, 2020 and if the FERC requires utilities to reflect cloud computing implementation costs in Prepayments (Account 165), I&M proposes to include these cloud computing implementation prepayments in rate base with amortization expense recorded to applicable O&M expense accounts. Cloud based implementation costs are incurred up front and provide benefits over the future period that the application is used, in the same manner that an on-site software application benefits the future period of use.

17. Chad M. Burnett, Director of Economic Forecasting American Electric Power Service Corporation. This testimony presents the kilowatt-hour (kWh), customer, and kilowatt (kW) forecasts that I&M used to develop its test year billing determinants. This testimony also discusses the process and methodology that I&M employed to forecast the Test Year.

I&M generates a new load forecast once a year as part of its normal planning process. The Company develops the load forecast utilizing modeling techniques that are both sophisticated enough to produce accurate results yet simple enough to be shared and understood by stakeholders. The load forecast is one of the first inputs used in the development of I&M's long-term financial forecast and is typically completed in the summer months while the rest of I&M's work plans are still being developed. Because the load forecast is completed early in the planning process, I&M monitors its performance during the second half of the year to ensure that it accurately predicts the most recent actual results and, if necessary, may update the load forecast.

The load forecast used in this proceeding was originally completed in June 2018 using actual data through December 2017. I&M made a slight upward adjustment to the forecast in October 2018 to reflect that I&M's service territory experienced a slightly better near-term economic recovery than was originally assumed.

I&M also prepares forecasts of customers, energy sales (kWh), and demand (kW) to provide planning information for a variety of business uses, including financial, fuel, capacity, and rate planning. I&M uses both short-term and long-term forecasting to develop its forecasts in order to take advantage of the relative strengths of each methodology. In this case, a short-term forecast of customers and kWh was used as a reference to confirm the long-term forecast's accuracy. The results of the short- and long-term kWh sales models are inputs to the Company's demand models. I&M developed an hourly load forecast by aggregating hourly load representations by class and load type and, if necessary, calibrating the system load profile by load factor trends. I&M utilizes data from several reliable sources in preparing input kWh sales, customer, demand, economic, appliance saturation, DSM/Energy Efficiency, and large customer assumptions and inputs to the load forecast. I&M's Test Year forecast assumes normal weather conditions, which represent the most likely outcome throughout the entire forecast horizon, including the Test Year.

The Company's load forecast methodology is reasonable, utilizes widely-accepted forecasting techniques, and has proven to produce accurate and reliable projections that are useful for planning and setting rates. For example, the load forecast used to develop the billing determinants in I&M's last base rate case (Cause No. 44967) was within 0.5% of the Company's actual 2018 Indiana retail sales. The economic forecast for I&M's Indiana service territory projects slight increases in population growth in I&M's Indiana service territory, gross regional product for Company's Indiana service territory, and non-farm employment through 2020. It predicts the end of the current business cycle and beginning of the next recession in 2020. I&M's total company forecasted peak demand for the Test Year is expected to be lower than its normalized peak in 2018, primarily due to the expiration of wholesale contracts and weaker economic conditions throughout the Company's service territory.

Company witness Nollenberger uses the Test Year load forecast to develop the forecasted billing determinants used in rate design. The load forecast is also used in the Company's jurisdictional and class cost study allocations sponsored by witnesses Duncan and High.

18. Jennifer C. Duncan, Regulatory Consultant Principal in the Regulated Pricing and Analysis American Electric Power Service Corporation. This testimony presents I&M's jurisdictional separation study and identifies several jurisdictional adjustments that are necessary to produce adjusted operating revenue that is specific to I&M's Test Year and its proposed basic rates. This testimony also explains I&M's proposal to implement the rate increase through a Phase-in Rate Adjustment (PRA) process that is consistent with the PRA used in I&M's last rate case.

The purpose of the jurisdictional separation study is to determine the Company's cost of providing service to the Company's Indiana retail jurisdiction. The forecasted jurisdictional study is also the source of data for the class cost-of-service study prepared by Company witness High. Certain portions of I&M's rate base, revenue, and expenses are utilized in common for service to retail and wholesale customers. Retail customers are served in the Indiana and Michigan jurisdictions, and wholesale customers in both states comprise the wholesale or FERC jurisdiction. Because I&M provides service in three jurisdictions, it was necessary to determine the rate base, revenues, and expenses that relate to serving I&M's Indiana jurisdictional retail customers. In order to accomplish this task, the study is prepared using the process of cost allocation and direct assignment. There are three basic steps to achieve this process. First, costs are functionalized into production, transmission, and distribution functions. Second, these costs are classified as demand, energy, or customer related. Third, the costs are directly assigned or allocated to a jurisdiction on the basis of an appropriate allocation methodology.

The same overall methods employed to develop the jurisdictional study in Cause No. 44967, the Company's last basic rate proceeding, were used to develop the jurisdictional study in this case. In February of 2019, 10% of I&M's Michigan retail customers elected to participate in Michigan's Electric Customer Choice program, thus switching their power supplier from I&M to a competitive supplier. To properly reflect this change, four new allocation factors were prepared: demand excluding shopping, energy excluding shopping, retail demand excluding shopping, and retail energy excluding shopping. These allocation factors are used to properly allocate the power supply costs related to service provided to Indiana and non-shopping Michigan customers. The use of the "excluding shopping" factors ensures that Michigan shopping customers are not being allocated costs for services that I&M no longer provides to them.

The Company's jurisdictional separation study properly determines the Company's cost of providing service to the Indiana retail jurisdiction, consistent with prior Commission guidance.

I&M's Test Year retail revenues include all revenues associated with I&M's current basic rates and existing rider mechanisms. I&M's OR-1 and RIDER adjustments restate I&M's Test Year retail revenue from I&M's Indiana customers and allows a comparison to I&M's proposed rates. This is accomplished in two distinct steps:

1. I&M's total Test Year retail revenues are recalculated on a tariff class level. The resulting variance to the Test Year forecast is represented by Operating Revenue Adjustment No. 1 (OR-1).

2. I&M's Test Year retail revenues are adjusted to remove all rider revenues that relate to costs I&M seeks to recover through its rider mechanisms. The resulting adjustments are represented by Adjustments RIDER-1 and RIDER-2.

The sum of I&M's Test Year operating revenues and the three adjustments above produces adjusted operating revenue that is specific to I&M's Test Year and its proposed basic rates.

I&M's proposed base rates in this proceeding are calculated based on forecasted rate base at Test Year end. I&M proposes to implement the requested rate increase in phases to reasonably reflect the utility property that is used and useful at the time rates are placed into effect as well as changes in wholesale load levels during the Test Year. The PRA is the mechanism that will be used to implement this phase-in. The PRA process and methodology is consistent with the settlement agreement approved in I&M's last base rate case, Cause No. 44967.

The PRA establishes a three-step phase-in of new base rates, as described below:

Phase	Date Range	Description	Effective Increase	
Phase I	When new base rates are implemented through May 31, 2020.	The PRA will reflect two rate credits: (a) a rate credit for non-fuel revenue received from the IMMDA wholesale contracts ("IMMDA Credit", and (b) a rate credit to reflect forecasted plant additions during the Test Year ("Forecasted Plant Credit").	Total Proposed: IMMDA Credit: Forecasted Plant Credit: Phase I Increase:	$172,004,651 ($46,442,922) ($43,051,354) $82,510,375
Phase II	June 1, 2020 through I&M's compliance filing on or after January 1, 2021.	On June 1, 2020, the IMMDA Credit will automatically expire. The full Forecasted Plant Credit will continue.	Total Proposed: Forecasted Plant Credit: Phase II Increase:	$172,004,651 ($43,051,354) $128,953,297
Phase III	After I&M's compliance filing.	The Forecasted Plant Credit will be reduced or eliminated based on I&M's compliance filing and the review process described below.	Phase III Increase:	$172,004,651

As discussed by Company witness Williamson, the majority of I&M's wholesale contracts with IMMDA members will end June 1, 2020. Adjustment OR-2, supported by Company witnesses Williamson and Nollenberger, annualizes the effect of the end of the IMMDA contracts. However, if new rates go into effect before the IMMDA contracts expire, I&M's rates should include a credit to reflect the non-fuel revenue I&M will receive from the IMMDA contracts through May 31, 2020. The IMMDA Credit ensures that customers realize the benefit of the IMMDA contracts while they are still in place. The IMMDA Credit is calculated by Company witness Nollenberger.

I&M's base rate cost of service reflects a forecasted Test Year end net plant-in-service balance. Upon implementation of the Test Year end base rates, the PRA will reduce customer rates to effectively reflect net plant-in-service (gross plant in-service less accumulated depreciation) and cost of capital as of December 31, 2019, which is representative of the beginning of the Test Year. 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 after they are placed in service and are used and useful in the provision of service for customers. The calculation of the Forecasted Plant Credit is described below.

On or after January 1, 2021, I&M will make a compliance filing in this docket that certifies its actual Test Year end net plant-in-service balance and reduces or eliminates the Forecasted Plant Credit to establish Phase III rates. Phase III rates will be determined using the lessor of (a) I&M's forecasted Test Year end net plant approved by the Commission in its final order in this proceeding or (b) I&M's certified Test Year end net plant. Within 60 days following the compliance filing, the OUCC and intervenors may state objections to I&M's certified Test Year end net plant. If there are objections, a hearing will 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 are placed in effect). This compliance filing procedure is the same method outlined in the settlement agreement approved in Cause No. 44967.

The revenue requirement calculated for the Company's proposed Forecasted Plant Credit Phase-In Rate Adjustment (PRA) appropriately determines the Company's cost of providing service to the Indiana retail jurisdiction, net of plant activity forecasted to occur in the Test Year.

19. Daniel E. High, Staff Regulatory Consultant in the Regulatory Strategy Department American Electric Power Service Corporation. The cost allocation methodology used in I&M's class cost-of-service study assigns costs among the customer classes in a fair and equitable manner based on principles of cost causation. Customers who cause costs to be incurred are allocated such costs in the Company's class cost-of-service study.

A jurisdictional allocation of rate base, revenue, and expenses was prepared for the forecasted Test Year by Company witness Duncan. The Indiana retail rate base and expense components were then assigned to the various customer classes using the standard three-step process to assign costs: functionalization, classification, and allocation. When this process is completed and all of the costs are allocated to the customer classes, the result is a fully allocated cost-of-service study that establishes cost responsibility and the Test Year rate of return earned from each class, making it possible to determine the rates each class of customer should pay based on costs that are just and reasonable.

The allocation methodology utilized in the Company's cost-of-service study was chosen while considering each of the following criteria:

- The method should match customer benefit from the use of the system with the appropriate cost responsibility for the system.
- The method should reflect the planning and operating characteristics of the utility's system.

- The method should recognize customer class characteristics such as energy usage, peak demand on the system, diversity characteristics, number of customers, etc.
- The method should produce stable results on a year-to-year basis.

The results of the cost-of-service study for the forecast period can be relied upon to determine the appropriate revenue requirement for I&M's customer classes.

The Company is proposing to continue using the 6 CP (Coincident Peak) demand allocator, consistent with the 6 CP methodology found appropriate in Cause No. 44075 and that which was used by I&M in Cause No. 44967, the Company's most recent basic rate case. More specifically, the six months that were used to derive the production, transmission, and primary distribution demand allocation factors were the three summer months of June, July, and August and the three winter months of December, January, and February for the Test Year. The importance of these six months is that Company engineers plan and size equipment (***e.g.***, poles, lines, and transformers) to meet customers' maximum expected demand on those facilities during the peak months in the summer and winter. The benefit of the 6 CP demand allocator is that each customer class is being allocated their fair share of demand costs based on their contributions to the average of the six monthly peaks during the Test Year.

Forecasted sales revenue was directly assigned to each class. Demand-related system sales and interruptible sales revenues were allocated based on the PROD_DEMAND allocation factor. Energy-related system sales and interruptible sales revenues were allocated based on the PROD_ENERGY allocation factor. Forfeited discounts and miscellaneous service revenues were directly assigned based on an analysis of accounting records. The functional components of rent from electric property and other electric revenue were obtained directly from the jurisdictional study and allocated to classes based on corresponding functional plant ratios.

The functionalized components of depreciation and amortization expense were allocated using the corresponding plant items. The functional components of regulatory debit and credit expense were obtained directly from the jurisdictional study and allocated using the appropriate plant allocation factor. Individual other tax items were allocated and classified using the appropriate demand, revenue, or plant allocator.

The class cost-of-service study equitably allocates costs among the customer classes based on contributions to demand and energy levels and number of customers. The results of the study help guide the allocation of the proposed changes in sales revenue to each customer class, as explained by Company witness Nollenberger.

In addition to the Test Year class cost-of-service study developed in this filing, Company witness High performed an additional class cost-of-service study in support of the Company's proposed PRA mechanism, which is supported by Company witness Duncan. It uses as its inputs the PRA jurisdictional separation study prepared by Company witness Duncan, and was prepared in a manner that was consistent with the Test Year class cost-of-service study.

20. Matthew W. Nollenberger, Manager, Regulated Pricing and Analysis American Electric Power Service Corporation. Mr. Nollenberger's testimony supports adjustments to the jurisdictional separation study. and the calculation of I&M's required jurisdictional rate relief for each tariff class. He also presents the rate design supporting I&M's proposed tariffs, including: Residential class energy and monthly service charges; an optional residential class demand-metered tariff; the introduction of demand charges for select end-use tariff classes and the Company's rider factor calculations. Mr. Nollenberger also presents a comparative billing analysis.

The jurisdictional adjustments computed by Mr. Nollenberger are: Adjustment OR-2 (IMMDA contract revenue) and Adjustment O&M-8 (remove leap year energy usage and fuel expense).

Following the same methodology established in Cause No. 44075 and reflected in Cause No. 44967, I&M's entire traditional embedded cost of transmission, as well as the revenues the Company receives from PJM as a Transmission Owner, have been removed from the Company's revenue requirement in this proceeding.

The Company's overall revenue increase among the customer classes was allocated following certain ratemaking principles to meet several objectives. First, and as an over-riding tenet, Mr. Nollenberger ensured the principle of cost causation by basing the revenue allocation on the Company's proposed cost of service. Second, he applied the principle of gradualism when determining the individual customer class revenue increases. Third, he allocated the total revenue increase in a manner that moved all classes closer to earning the class average rate of return. Fourth, and related to the third objective, he reduced the current level of inter-class revenue subsidies. Finally, he ensured that no class received a revenue decrease based on cost of service. Each of these principles and objectives were also applied in the development of the Company's proposal to eliminate 25% of the current subsidies from all classes.

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

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

The Company's collection of revenues under the existing residential service rate design (largely recovered through volumetric charges), does not align with the predominately fixed cost of providing electric service to residential customers. Approximately 77% of I&M's costs required to serve the residential class are fixed, demand-related costs, as classified by cost of service. Energy and customer-classified costs account for approximately 13% and 10% of total costs, respectively.

In contrast, under the current structure approximately 89% of total residential costs are recovered through volumetric energy charges, while approximately 11% of customer costs are recovered through the fixed monthly service charge. This illustrates a clear mismatch between I&M's current cost components and the current rate components associated with serving the residential customer class. In other words, the Company's collection of revenues, largely recovered through volumetric charges, does not align with the predominately fixed cost of providing electric service to residential customers.

Today's residential service (Tariff R.S.) rate structure presents several challenges for both customers and the Company alike.

- First, given the weather-sensitive nature of the customer class' energy usage, residential customers' monthly bills are subject to greater volatility when a disproportionate amount of fixed costs are included in the volumetric energy charge.

- Second, today's Tariff R.S. rate design does not send price signals that effectively reflect the underlying nature of the costs incurred to serve the Company's residential customers. This can create problems when a customer makes investments to reduce their energy usage and expect equal and offsetting reductions in the costs required for service. Thus, an improper price signal sent through rate design can lead to inefficient investment decisions by customers.

- Third, a rate design that recovers a disparate amount of fixed costs through volumetric energy charges has the potential to introduce intra-class subsidies paid by high energy users to low energy users.

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

Since demand-related costs do not vary with the amount of electricity consumed, it is appropriate to recover a greater proportion of those fixed costs through fixed charges, rather than recovering a disproportionate amount of those costs through volumetric, per-kWh charges.

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

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

By designing the residential monthly service charge and first block energy charge to recover all secondary distribution costs along with customer-related costs, the Company has better aligned the collection of those costs with the local, fixed nature of those costs. Secondary distribution costs, such as the poles, wires and transformers seen in neighborhoods, represent those costs closest to the customer and those costs that are required to connect the customer to the higher voltage grid.

Figure MWN-3 shows a slight increase in the proportion of demand-related costs now recovered in the monthly service charge, versus the amount of demand-related costs recovered in the current monthly service charge. The remainder of all proposed demand- and energy-related costs (88%) is recovered in the volumetric energy charges.

I&M's declining block volumetric rate proposal in this proceeding is consistent with collects the same amount of energy-related costs, approximately 1.2 cents/kWh. The Company's declining block energy rate conforms with the Commission's guidance that PURPA refers only to the energy cost component of a utility and does not prohibit declining block rates which reflect the recovery of customer and demand related costs.

By recovering a more proportionate amount of fixed demand-related costs in the fixed monthly service charge and first block of the volumetric energy charge, the Company's proposed rate design sends more accurate price signals to residential customers than under the current rate structure. The proposed rate design also allows customers to make more informed decisions regarding the benefits of their energy usage relative to the true cost of their usage. The combination of lower volumetric energy charges, declining block rates and increased customer charges provides greater month-to-month bill stability for residential customers that are sensitive to weather extremes.

Importantly, it should be recognized that the percentage increase in the monthly service charge relates only to one component of the customer's entire bill and should not be confused as equating to an overall increase in the entire bill. As previously recognized by the Commission, gradualism is best considered in the context of the entire customer bill and not discrete charges within the bill.

A common misconception is that low income customers use significantly less energy than average or above average income customers. However, like other residential customers, low income customers are weather-sensitive energy customers. Some may need to keep their homes warmer in the winter or cooler in the summer because of medical or other needs. Therefore, collecting a disproportionate amount of fixed costs through volumetric charges can expose these customers to more severe bill impacts during periods of weather extremes.

A review of 2018 Company data illustrates that I&M's Indiana residential customers on assistance programs use noticeably similar amounts of annual energy as compared to those residential customers that are not on assistance programs. Furthermore, in the winter months, the average assistance user used roughly the same amount or more electricity than the average non-assistance customer. This suggests that a significant portion of I&M's Indiana assistance customers rely on electricity for their winter space heating needs. More importantly, the data suggests that the Company's proposal to recover a more proportional amount of fixed costs through both the fixed service charge and declining block energy charge can actually benefit the average assistance customer during the winter months when they rely on electricity the most. As illustrated in Figure MWN-5, the Company's proposal provides a bill reduction to the average large assistance customer of over $11.00 per month when compared to the current residential rate design. Moreover, the average savings to the large assistance customer during the peak winter month of December is over $30. Conversely, when compared to the current rate design, the Company's proposal results in an average bill increase of less than $3 per month for the remaining 90% of assistance customers.

As discussed by Company witness Cooper, I&M is proposing a new optional residential rate scheduled called Tariff RSD (Residential Service - Demand-Metered). Tariff RSD is designed to provide a rate structure that is more reflective of the Company's residential class cost structure. Tariff RSD provides I&M's residential customers with an additional tariff option to manage their monthly bills. Under the Company's current standard residential rate structure, which features a two-part rate design, customers are limited to increasing or decreasing their electricity usage to change the total amount of their monthly bill. Under Tariff RSD, customers are provided a demand charge as a third dimension to control their bills by managing the peak intensity of their use. The rates for Tariff RSD were calculated on a revenue-neutral basis relative to the existing residential tariff class, using the residential class target revenues and billing determinants proposed in this case.

21. Kurt C. Cooper, Regulatory Consultant Principal in the Regulatory Services Department Indiana Michigan Power Company. I&M is proposing modifications to its tariff book, including changes to I&M's Terms and Conditions of Service to include revised rates for various, one-time service and disconnection / reconnection charges. The Company is requesting to increase or decrease the existing rate charged for these one-time charges to align with the cost to perform the specific service.

I&M is proposing to add a paragraph to its Terms and Conditions to inform customers of data that is collected during the normal course of business and how that data is used and protected. Given the ever-evolving nature of data privacy, the Company uses its website to keep customers informed as to the Company's current data privacy policy. This provides an efficient means of keeping customers informed. The revised tariff also incorporates language for the new pilot programs proposed by I&M in this proceeding, including the new pilot Tariff R.S.D. for residential customers interested in demand metered service.

I&M is also proposing tariff language regarding AMI opt-outs. I&M recognizes that for a variety of reasons, a small percentage of customers may not want the installation of an AMI meter at their residence. The proposed tariff language allows a customer to opt out, or decline, the use of this new technology and instead be served through a standard Radio Frequency (RF) meter. This proposal would include a 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. Both charges are cost-based.

The Company is proposing to close the Optional Unmetered Service Provision under Tariff G.S. from participation by any additional accounts. Historically, this tariff was a good option for situations where the usage is predictable and unlikely to vary. An example of this would be billboards, which often had just a couple of floodlights and were somewhat inaccessible for meter reading. Changes in technology have resulted in the potential for dramatic changes in electric use under this tariff. Unless the customer notifies the Company of a change in usage, the customer is not getting billed for the correct usage amount. Further, the development and use of RF and AMI metering technology that can be read remotely provides an efficient means of metering these types of services. Closing this service from any new accounts also addresses a safety concern with this unmetered service.

The Company is proposing two changes to the Economic Development Rider (EDR). The first change is to remove the language that would close the EDR to new applicants on and after January 1, 2021. Related to this, the Company proposes to remove language stating that EDR billing credits would terminate no later than December 31, 2027. This change promotes administrative efficiency and makes it easier for I&M and its economic development partners to promote the EDR. The second change is to clarify how the monthly billing credit is determined. This change is intended to clear up an ambiguity with the existing credit calculation language. The EDR language changes complement the ongoing economic development activities discussed by Company witness Lucas.

The Company is proposing to consolidate its GPR (Green Power Rider) and REO (Renewable Energy Option) offerings into one voluntary IM Green Rider that will offer the ability to purchase a combination of wind and solar Renewable Energy Credits (RECs). Under the IM Green Rider, customers will be able to purchase RECs as a percentage of their monthly kWh usage. Recognizing that customers can go out to the market to purchase RECs, the IM Green Rider offers a market-based cost of RECs to customers that are interested in this type of voluntary REC purchase program. Larger commercial and industrial customers could take advantage of the program to meet their companies' renewable energy obligations.

22. I&M Exhibit A (Financial Exhibit), including index of schedules. I&M Exhibit A consolidates the data supporting I&M's projected costs and revenues for the Test Year. Each Test Year adjustment is sponsored and described by an I&M witness, as shown in I&M Exhibit A. I&M Exhibit A-1 presents I&M's overall requested rate relief for the Test Year, including I&M's proposed base rates and riders. I&M Exhibit A-2 presents the Test Year balance sheet. I&M Exhibits A-3 and A-4 present the Statement of Cash Flows and Income Statement, respectively, for the Test Year. I&M Exhibit A-5 identifies the net operating income per books and adjusted for ratemaking purposes and identifies the associated adjustments. I&M Exhibit A-6 sets forth the Test Year rate base and related adjustments. I&M Exhibit A-7 presents the capital structure and cost of capital for the Test Year. Finally, I&M Exhibits A-8 and A-9 present the calculation of the gross revenue conversion factor and the effective tax rate, respectively, for the Test Year. The items included in I&M's Exhibit A satisfy Section 6 of the MSFRs for the Test Year.