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 OF CAPITAL INVESTMENT; (4) RATE ADJUSTMENT MECHANISM PROPOSALS; (5) CUSTOMER PROGRAMS: (6) WAIVER OR DECLINATION OF JURISDICTION WITH RESPECT TO CERTAIN RULES; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	))))))))))))))	**CAUSE NO. 45576**

DIRECT TESTIMONY AND EXHIBITS

OF

MARK E. GARRETT

ON BEHALF OF

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR ("OUCC")

PUBLIC'S EXHIBIT NO. 2

OCTOBER 12, 2021

Respectfully submitted,

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PUBLIC'S EXHIBIT NO. 2

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark E. Garrett. My business address is 4028 Oakdale Farm Circle, Edmond, Oklahoma 73013.

Q: WHAT IS YOUR PRESENT OCCUPATION?

A: I am the President of Garrett Group Consulting, Inc., a firm specializing in public utility regulation, litigation and consulting services.

Q: WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION?

A: I received my bachelor's degree from The University of Oklahoma and completed post graduate hours at Stephen F. Austin State University and the University of Texas at Arlington and Pan American. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, private industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of Texas. In private industry, as controller for a mid-sized corporation in Dallas, I managed the company's accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission ("Commission") from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma.

Since leaving the Commission, I have worked on numerous rate cases and other regulatory proceedings on behalf of various consumers, consumer groups, public utility commission staffs and attorney general's offices. My clients primarily include industrial customers, hospitals and hospital groups, universities, municipalities, and large commercial customers. I have also testified on behalf of the commission staff in Utah and the offices of attorneys general in Oklahoma, Washington, Nevada and Florida. I have also served as a presenter at the NARUC subcommittee on Accounting and Finance on the issue of incentive compensation, and as a regular instructor at the New Mexico State University's Center for Public Utilities course on basic utility regulation.

Q: HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A: Yes. I have provided testimony before the public utility commissions in the states of Alaska, Arizona, Arkansas, Colorado, Florida, Indiana, Massachusetts, Nevada, New Mexico, Oklahoma, South Carolina, Texas, Utah, and Washington. My qualifications were accepted in each of those states. A description of my qualifications and a list of the proceedings in which I have been involved are attached as Attachment MG-1.

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A: I am appearing on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC").

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to address various revenue requirement issues identified in the rate case application filed by Indiana Michigan Power Company ("I&M" or "Company"), an operating company of American Electric Power Company, Inc. ("AEP"). In this filing, I&M is requesting a $110.7 million increase in rates. In my testimony, I provide recommendations and adjustments to the Company's requested revenue requirement.

Q: HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A: Yes. Schedules MG-1 through MG-22 are attached to my testimony. These schedules present my findings and recommendations and include the recommendations and proposed adjustments sponsored by other OUCC witnesses. Adjustments sponsored by other OUCC witnesses are also summarized in Sections III through VI of my testimony.

Q: TO THE EXTENT THAT YOU DO NOT ADDRESS A SPECIFIC ITEM OR ADJUSTMENT, SHOULD THAT BE CONSTRUED TO MEAN THAT YOU AGREE WITH THE COMPANY'S PROPOSAL FOR THAT ITEM?

A: No. Exclusion from my testimony of any specific adjustments or amounts proposed by I&M does not indicate my approval of those adjustments or amounts, but rather that the scope of my testimony is limited to the specific items addressed herein.

II. RECOMMENDED ADJUSTMENTS

II. A. REMOVE HYPOTHETICAL NET OPERATING LOSS CARRYFORWARD

Q: PLEASE DISCUSS I&M'S PROPOSED ADJUSTMENT TO ESTABLISH A NET OPERATING LOSS CARRYFORWARD ("NOLC") BALANCE ON THE BOOKS OF I&M FOR NET OPERATING LOSSES THAT HAVE BEEN USED AT THE PARENT COMPANY LEVEL AS PART OF A CONSOLIDATED TAX RETURN.

A: Jessica M. Criss discusses I&M's tax expense and Accumulated Deferred Income Taxes ("ADIT") in her Direct Testimony. Ms. Criss argues that I&M's ADIT balances (cost free capital) should be reduced by a stand-alone NOLC calculated for I&M based on her interpretation of tax normalization rules.[1] Ms. Criss acknowledges that this is a change from the ADIT balances included in I&M's most recent rate case.[2] Ms. Criss proposes an adjustment to reduce the ADIT cost free capital component by $159,604,598.[3] In I&M's projected capital structure, the revised amount is a $205,672,569 reduction to the ADIT balance. [4]

Q: DOES I&M FILE ITS OWN STAND-ALONE TAX RETURN?

A: No. I&M's operating income is included in the AEP consolidated tax return. AEP is the tax paying entity, not I&M.·[5]

[1] See Direct Testimony of Jessica M. Criss, p. 8, line 15 – p. 9, line 2.
[2] *Id.*, p. 14, line 21 – p. 15, line 2.
[3] *Id.*, p. 18, lines 8-10.
[4] *Id.*, p. 13, lines 22-23.
[5] *Id.*, p. 8, lines 4-5.

Q: DOES AEP HAVE A CONSOLIDATED NOLC?

A: No. Ms. Criss acknowledges that as of the end of the test year, the AEP consolidated group had no NOLC.[6] Instead, any NOLs generated from subsidiary companies within the consolidated group, such as I&M, have been used to offset taxes at the parent company (AEP) level.

Q: DOES I&M ACTUALLY HAVE AN NOLC RECORDED IN ITS BOOKS AND RECORDS, IN EFFECT, ON ITS BALANCE SHEET?

A: No. The AEP operating companies record only the allocated share of the consolidated company (AEP) NOLC. I&M did not record an NOLC after 2017 because AEP did not have any NOLC to allocate to it.[7] I&M's NOLC had already been used to reduce taxes at the AEP level.

Q: WHY IS ADIT INCLUDED IN THE CAPITAL STRUCTURE AND WHY IS NOLC A REDUCTION TO ADIT?

A: ADIT is included in the cost of capital because it represents money collected from ratepayers that has not yet been remitted to the IRS, mainly because of book/tax timing differences related to the accelerated depreciation on plant for tax purposes. This money – collected from ratepayers and not yet remitted to the IRS – is cost-free capital to the utility and, as such, is included in the cost of capital. This the universally accepted treatment of ADIT for ratemaking purposes across the country.

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[6] *Id.*, p. 13, lines 17-18.
[7] See Attachment MG-2, OUCC Data Request ("DR") 9-02.

An NOLC reduces ADIT (for ratemaking purposes) because it reflects the amount of ADIT that has not yet been used to reduce taxes. So, the net amount of the ADIT credit and the NOLC debit is the actual amount of money collected from ratepayers not yet used to reduce taxes paid to the IRS. This is the generally accepted treatment of ADIT and NOLCs. Whether it is viewed as capital supplied by ratepayers or by the IRS, it is generally agreed that ADIT is a source of cost-free capital to the utility and should be included as such.[8]

Q: HAS I&M ALREADY RECEIVED THE TAX BENEFITS OF ITS NOLC?

A: Yes. AEP companies have a tax-sharing agreement that provides for payments for tax deductions that an operating company cannot use on a stand-alone basis to the extent the excess deductions can be utilized by the consolidated group.[9] I&M was therefore able to realize the full benefits of its tax deduction as a member of the AEP consolidated group and received the full amount of the cost-free capital reflected in the ADIT balances.

Q: DID I&M RECEIVE COST-FREE CAPITAL FOR THE NOLC THAT WENT TO AEP?

A: Yes. Pursuant to the Consolidated Tax Sharing Agreement, AEP paid I&M for the use of its NOLC. This is capital that came to I&M cost-free, unlike its other forms of capital,

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[8] Some utilities include ADIT as a reduction to rate base, which has the same impact on the revenue requirement as including it as zero cost capital.
[9] See Attachment MG-3, Joint Municipals DR 1-13.

such as debt and equity. As a result, it *must* be reflected as an increase in ADIT (in the capital structure) as the Company's actual accounting records reflect.

Q: DOES THE AEP CONSOLIDATED TAX SHARING AGREEMENT REQUIRE THAT I&M BE PAID FOR ANY NOLC USED BY THE PARENT?

A: Yes. The AEP consolidated group tax sharing arrangement requires that a member with a negative tax allocation will receive a payment from the holding company in the amount of its negative allocation. The payment equals the amount by which the consolidated tax is reduced by including the member's net corporate tax loss in the consolidated tax return. This means I&M has been paid in full for any NOLC used by AEP, which is the full amount of its hypothetical NOLC in this case.

Q: **MS. CRISS ARGUES THAT THE NOLC ADJUSTMENT IS NECESSARY TO RESTORE THE CAPITAL THAT WAS REDUCED BY THE COST SHARING AGREEMENT. IS THAT CORRECT?**

A: No. Ms. Criss asserts that the NOLC adjustment is necessary or the members of the holding company would have different capital costs than a stand-alone company.[10] Respectfully, Ms. Criss is mistaken on that point. The holding company provides the operating companies several benefits not available to stand-alone companies including better access to capital, economies of scale, and operating synergies. However, that is a part of the bargain which allows holding companies to own regulated utilities. I&M cannot

[10] Criss, p. 22, line 10 – p. 23, line 2.

participate as a subsidiary operating company in a consolidated group when it benefits AEP but create a fictional capital structure as if it were a stand-alone company to also retain those benefits for itself on a separate company basis. This treatment is wrong because in deprives ratepayers of the benefit of the cost-free capital received by I&M.

Q: MS. CRISS ASSERTS THAT A STAND-ALONE NOLC ADJUSTMENT IS NECESSARY BECAUSE OF NORMALIZATION CONSISTENCY REQUIREMENTS. DO YOU AGREE?

A: No. If I&M's NOL had not been used to reduce taxes at the consolidated AEP level and remained on I&M's books as of the test year end, that amount would be required to be reflected as a NOLC ADFIT asset, to reflect the fact that the amount had not provided cost free capital by reducing the amount of taxes paid. That, however, is not the case. The amount I&M seeks to include is a derived amount based on I&M *hypothetically* filing a stand-alone tax return. The NOLC ADFIT asset that I&M seeks to include in the capital structure no longer exists on its books because it *has* been used to reduce taxes. I&M provides a detailed discussion of the normalization rules that may give the impression that the rules require the treatment I&M requests in this case, but they do not.

Q: ARE THERE OTHER REASONS IT IS HIGHLY UNLIKELY A NORMALIZATION VIOLATION WILL OCCUR IN THIS INSTANCE?

A: The operating companies of AEP have been filing rate cases for years without reinstating their stand-alone NOLCs, and this practice has never caused a normalization violation.

For example, I&M's sister company SWEPCO did not file a reinstated stand-alone NOLC in its 2016 rate case,[11] and in the five years since, no normalization violation occurred. PSO, another of I&M's sister companies, did not file a stand-alone NOLC in its 2017 rate case and no normalization violation or inconsistency occurred. Similarly, I&M did not file a stand-alone NOLC in its 2019 rate case,[12] and in the two years since that filing no normalization violation has occurred. If the failure to file a *hypothetical* NOLCs at AEP's operating companies actually caused a normalization violation, it likely would have occurred many years ago. To my knowledge, there has been no change in the tax law to justify the filing of a hypothetical NOL at the subsidiary level, when the NOL has been fully utilized by the parent company. The generalized concern that there *may* be a potential normalization inconsistency seems an inappropriate excuse for creating a fictional capital structure change at the I&M level. Moreover, it appears to be based on a misinterpretation of the normalization rules.

Q: IS THERE OTHER EVIDENCE A NORMALIZATION VIOLATION WILL NOT OCCUR IF THE HYPOTHETICAL NOLC IS NOT REINSTATED AT THE OPERATING COMPANY LEVEL?

A: Yes. The AEP operating companies have been in NOLC positions fairly regularly from 2009 forward. This means that these subsidiary members of the AEP Consolidated group

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[11] *In re Southwestern Electric Power Co.*, Docket No. 46449 (Pub. Util. Comm'n of Tex. Jan. 11, 2018) ("PUCT Docket No. 46449").

[12] *In re Indiana Michigan Power Co.*, Cause No. 45235 (Ind. Util. Regul. Comm'n Mar. 11, 2020) ("Cause No. 45235").

have been sharing their NOLC positions with the parent company on an ongoing basis for roughly 12 years. If I&M's claims in this proceeding are true – that I&M should reflect its NOLC on a stand-alone basis with no sharing reflected in the balance – it would have been equally true for the past 12 years. I&M, and all of the other AEP operating companies, would have been committing normalization violations consistently for at least 12 years now. It is difficult to believe that the IRS, which presumably is quite familiar with AEP's tax sharing arrangement, would not have alerted AEP regarding this potential normalization violation over the past 12-year period.

Q: ARE THERE OTHER REASONS YOU ARE NOT AS CONCERNED ABOUT A POTENTIAL NORMALIZATION VIOLATION IN THIS INSTANCE?

A: Yes. In my experience, normalization violations are extremely rare because typically the IRS gives regulated utilities time to cure any potential normalization/consistency rule violation. It is my understanding that the only time a normalization violation would result in penalties would be a situation where a state regulatory commission order resulted in a violation ***and*** the commission refused to amend its order to cure the violation after being notified of the problem.

Q: IS A NORMALIZATION VIOLATION A SERIOUS PROBLEM?

A: In theory, yes; in practice, no. In theory, a normalization violation would be a serious problem because such a violation, if left uncured, could result in the utility losing its ability to take accelerated depreciation for tax purposes. In my experience, however, this does not happen because it would only occur after a regulatory commission's willful refusal to amend an order that caused a violation.

Q: IS IT COMMON FOR UTILITIES TO RAISE NORMALIZATION VIOLATION CONCERNS IN AN ATTEMPT TO KEEP TAX SAVINGS THAT SHOULD GO TO RATEPAYERS?

A: Yes. I have been involved in several cases over the past few years in which utilities have raised normalization violations in attempts to keep some of the Tax Cuts and Jobs Act ("TCJA") tax savings that were intended for ratepayers.[13] In those cases, the utilities argued that retaining some portion of ratepayers' prepaid taxes (via excess deferred income taxes ("EDIT")) rather than refunding them to ratepayers was required under the IRS' "consistency rule," and was necessary to avoid potential normalization violations.[14] Fortunately, in those cases, the regulatory commissions, and the courts in those instances when the commission orders were appealed, did not accept the utilities' arguments about normalization violations and instead ordered that the money be returned to ratepayers. No normalization violation has resulted from any of these cases.

Q: DOES MS. CRISS PROVIDE OTHER SUPPORT FOR THIS NEW POSITION?

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[13] *See, e.g., In re Puget Sound Elec.* Co., Docket Nos. UE-190529 and UG-190530, Final Order 08, pp. 109-114 (Wash. Util. & Transp. Comm'n Jul. 8, 2020) ("WUTC Docket No. UE-190529"); *In re NV Energy*, Docket Nos. 18-02010, 18-02011, 18-02012, Order pp. 26-30 (Pub. Util. Comm'n Nev. Oct. 8, 2018); *In re El Paso Elec. Co.*, Docket No. 20-00104-UT, Recommended Decision, p. 108 (N.M. Pub. Regul. Comm'n Apr. 6, 2021); *In re Southwestern Elec. Power Co.*, Docket No. 51415 (Pub. Util. Comm'n of Tex.) ("PUCT Docket No. 51415").
[14] *See* WUTC Docket No. UE-190529, Final Order 08, p. 110, ¶368.

A: Yes. She references several private letter rulings ("PLR") that she claims support her new calculations. They do not. These PLRs merely conclude that the NOLC-related account balances associated with accelerated depreciation must be included in the revenue requirement to avoid normalization violations, which was already known and generally agreed with. I&M's actual NOLC balance is $0 in its books and records and *is* included in the revenue requirement. It is important to remember that a consolidated group is considered a single entity by the IRS for tax purposes. The PLRs relied upon by Ms. Criss do not support the Company's proposed adjustment to reinstate an NOLC for a stand-alone subsidiary when the NOL has been fully utilized by the consolidated group. Moreover, PLRs are taxpayer specific and considered non-precedential, as noted by Washington commission:

> **372** Second, PSE's ***reliance on PLRs to support its position is misplaced***. Specifically, PSE provides examples in the context of assets that are sold or deregulated, neither of which has relevant application here. Moreover, ***PLRs are issued in response to specific taxpayer questions, apply only to the matter at hand, and are non-precedential***. The PLRs on which PSE relies are not instructive as to whether the Company may defer and use a separate schedule to return PP EDIT in the context of this general rate proceeding. As AWEC correctly observes, the IRS has yet to weigh in on inconsistency issues related to the TCJA. Until the IRS provides such guidance, we decline to give any weight to irrelevant PLRs and PSE's use of inconsistent estimates and projections under its interpretation of the IRS Normalization rules. ***If PSE seeks a PLR from the IRS on this subject, the Company should include the Commission in that process***.[15]

[15] *See* WUTC Docket No. UE-190529, Final Order 08, p. 110, ¶368 (emphasis added).

Q: HAS AEP INFORMED THE IRS THAT IT MIGHT BE IN VIOLATION OF THE NORMALIZATION RULES BY USING ITS ACTUAL NOLC OF ZERO IN ITS LAST RATE CASES?

A: No, which indicates to me that the Company is not seriously concerned about a normalization violation.

Q: HAS I&M REQUESTED A PRIVATE LETTER RULING ("PLR") REQUESTING THE IRS DETERMINE WHETHER THE COMPANY IS REQUIRED TO COMPUTE ITS NOLC ASSET ON A STAND-ALONE BASIS FOR EACH OPERATING COMPANY?

A: No. To my knowledge, neither I&M, nor AEP, has requested a PLR.

Q: HAS AEP ATTEMPTED TO INCLUDE HYPOTHETICAL NOLCS IN THE RATE CASES OF ITS OPERATING COMPANY SUBSIDIARIES IN OTHER JURISDICTIONS?

A: Yes. It appears to be a newly-developed strategy for several of the AEP operating companies. I do not know if each of AEP's subsidiary operating company has proposed this treatment, but I do know the argument was raised recently in Texas with SWEPCO. In the pending SWEPCO rate case, Docket No. 51415 (SOAH Docket No. 473-21-0538) AEP is attempting to increase rate base by approximately $455 million.[16] The Texas commission staff strongly opposed the Company's newly-proposed stand-alone NOL

[16] *PUCT Docket No. 51415*, Responsive Testimony of Ruth Stark, at p. 29.

adjustment in that case.[17] A preliminary order has been issued denying the SWEPCO NOLC adjustment. A similar request has been made in Oklahoma in the Public Service Company ("AEP-PSO") rate case filed this year, Cause No. PUD 2100055. The Attorney General and the Oklahoma Industrial Energy Consumers have both opposed the hypothetical NOLC adjustment in that case as well.

Q: WHAT DID THE TEXAS COMMISSION SAY ABOUT THE NOLC AND THE RISK OF A NORMALIZATION VIOLATION IN THE AEP-SWEPCO RATE CASE?

A: In that case, the four Administrative Law Judges included a comprehensive analysis of the NOLC issue in their proposed decision.[18] Regarding the risk of a normalization violation, the ALJs included the following finding:

> In the very least, disallowing SWEPCO's proposed adjustment does not "clearly violate" normalization requirements. Although ***insisting*** that disallowance risks a violation finding, Mr. Seltzer ultimately acknowledged ***that the IRS has not directly addressed the fact pattern presented in this case***. Moreover, as Staff points out, the ***IRS has recently issued guidance*** stating, with regard to determining the portion of NOLC attributable to depreciation, "*[r]egulating commissions have expertise in this area, and any reasonable method . . . should generally be respected provided such method does not clearly violate normalization requirements*." ***Disallowing the adjustment to prevent a doubling of the NOLC ADFIT's rate-base impact is well within these bounds of reasonableness.***[19]

Q: WHAT IS THE GUIDANCE ISSUED BY THE IRS?

A: Rev. Proc. 2020-39, issued August 14, 2020, which states:

[17] *Id*.
[18] *PUCT Docket No. 51415*, Proposal For Decision, pp. 80-91.
[19] *Id*., at p. 90 (emphasis added).

> Compliance with normalization requires a determination of the source of an NOLC ***so that rate base is not overstated*** in jurisdictions in which net deferred tax liabilities reduce rate base.[20]

Q: WHY WOULD ALLOWING THE NOLC IN RATES CREATE A DOUBLING OF THE NOLC IMPACT?

A: In SWEPCO, the NOLC is included in ADIT as a debit in ***rate base***; whereas with I&M, the NOLC is included as a debit to ADIT in the ***capital structure***. Both approaches have the same end result which is to include a return on the NOLC balance by reducing the amount of cost-free capital (in rate base and in the capital structure) by the NOLC amount. This results in a double counting of the NOLC amount because the cash received by the operating company in payment of the NOLC from AEP was invested in rate base where it earns a return. If it is also included as a debit to ADIT as an offset to the cost-free capital balance, the NOLC effectively earns a return a second time.

Q: WHAT DID THE PROPOSED TEXAS DECISION SAY ABOUT THE DOUBLE COUNTING PROBLEM?

A: The Proposal for Decision addresses the issue this way:

> Thus, because the amount of the tax-allocation payments is now part of SWEPCO's rate base, it follows that SWEPCO's NOLC ADFIT adjustment would duplicate rather than preserve the rate impact of the NOLC ADFIT. In addition to the $455,122,490 now in rate base that SWEPCO received in exchange for the NOLC ADFIT, SWEPCO's rate base would be increased by $455,122,490 again, through the adjustment's offsetting of ADFIT by that amount. ***Nothing in PURA § 36.060 requires this double-counting, and allowing it would also violate normalization principles by doubling the rate impact of the NOLC ADFIT***. Staff's proposal preserves the correct rate

[20] Rev. Proc. 2020-39, p. 8.

> impact of the NOLC AFDIT now that the tax-allocation payments are in rate base.[21]

In effect, the operating company is compensated twice for the same NOLC: once, when the assets purchased with the NOLC proceeds from AEP are included in rate base, and a second time if the hypothetical NOLC is embedded in the capital structure as an offset to the ADIT cost-free capital.

Q: WHAT DID THE TEXAS PROPOSED ORDER RECOMMEND AS TO THE NOLC ISSUE?

A: The four ALJs recommended rejection of the request to reflect a hypothetical NOLC at the operating company level:

> Accordingly, the ALJs recommend that the Commission disallow SWEPCO's proposed adjustment to deduct the $455,122,490 NOLC ADFIT asset from its ADFIT balance.[22]

Q: WHY DOES AEP HAVE SUFFICIENT TAXABLE INCOME TO UTILIZE THE NET OPERATING LOSSES OF ITS SUBSIDIARY OPERATING COMPANIES LIKE I&M AND SWEPCO?

A: AEP actually makes more money than the sum of its parts. In a more perfect world, AEP's income would be roughly equal to the sum of all of the incomes of its subsidiary operating company utilities. Here, however, AEP actually carries far more debt on its balance sheet than the operating companies do. For example, I&M is at about 51% equity (49% debt)

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[21] *PUCT Docket No. 51415*, p. 90.
[22] *Id.*

but AEP is only at 41% equity (59% debt). This means AEP is borrowing money at a little over 4% and sending those funds down to its subsidiaries as “equity” where the operating companies get a 9.7% return approximately. This capital structure arbitrage helps create excess income at the parent level sufficient to utilize the operating companies’ NOLC.

Q: WHAT IS YOUR RECOMMENDATION REGARDING I&M’S ADJUSTMENT FOR THE NOLC BASED ON A STAND-ALONE TAX CALCULATION?

A: I recommend that the hypothetical stand-alone NOLC not be used to reduce the balance of ADIT.

Q: WHAT ARE THE ADJUSTMENTS THAT YOU RECOMMEND TO PROPERLY RECOGNIZE THE TAX BENEFITS REALIZED BY AEP AND FUNDED BY RATEPAYERS?

A: I recommend adjustments to increase I&M’s total company pro form ADIT by $159,604,598, to be consistent with the Company’s actual books and records. This adjustment is found on Schedule MG-22.

Q: DID THE COMPANY PROPOSE OTHER ADJUSTMENTS RELATED TO THE HYPOTHETICAL NOLC?

A: Yes. The Company has proposed an adjustment to the Tax Rider related to its hypothetical NOLC adjustment.[23] The proposed adjustment to the Tax Rider should not be accepted

[23] Criss, p. 25, and Direct Testimony of Dona Seger-Lawson, pp. 41-44.

because the NOL has been used by AEP and is therefore not an NOL carryforward at the I&M level, as explained above. For this reason, the Company's proposed adjustment to the Tax Rider related to the NOLC should be reversed.

II. B. ANNUAL INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF AEP/I&M'S ANNUAL INCENTIVE COMPENSATION PLANS.

A: AEP/I&M's annual incentive compensation plans are formal written plans approved by senior management. In this application, I&M seeks to include in rates $17.024 million for I&M annual incentive expense and $5.849 million for AEPSC allocated annual incentive expense, for a total of $22.873 million annual incentive plan costs based on projected expense levels for test year ending December 31, 2022.[24]

Q: HAVE COMPANY WITNESSES DISCUSSED THE ANNUAL INCENTIVE COMPENSATION PLANS IN DIRECT TESTIMONY?

A: No. AEP/I&M's incentive compensation plans are not discussed in the testimony of the Company's witnesses. Copies of AEP's annual incentive compensation plans are included within the Company's Minimum Standard Filing Requirements.[25]

Q: WHAT IS THE COMMISSION'S STANDARD FOR THE INCLUSION OF INCENTIVE COMPENSATION IN RATES?

[24] See Attachment MG-4, I&M's response to OUCC DR 5-13, Attachment 1.
[25] Minimum Standard Filing Requirements ("MSFR"), Vol. 2 of 3, pp. 18-113.

A: In I&M's last rate case, Cause No. 45235, the Commission affirmed its use of a three-part test for evaluating the inclusion of incentive compensation.[26] The Commission noted that this standard was first established in Cause No. 42359 and has been consistently applied since.[27] The three-part test requires the following:

> The criteria for the recovery of incentive compensation plan costs is well established. We will allow recovery in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs.[28]

In I&M's last rate case, the Commission allowed full recovery of the utility's short-term and long-term incentive pay at target levels, based on the testimony and exhibits of I&M's rebuttal witness, Mr. Andrew Carlin.[29] The Commission stated, "[b]ased on Mr. Carlin's testimony, the Commission finds I&M's plan incorporates operational as well as financial performance goals and is not a pure profit sharing plan."[30] The Commission found that the second element of the Commission's standard was satisfied, as follows:

> No one claims I&M's total compensation levels are excessive, and Mr. Carlin's presentation of the salary bands in comparison to the medians confirms total compensation is not excessive. Petitioner's Ex. 40 at pp. 13-15.[31]

Finally, the Commission found, based upon Mr. Carlin's rebuttal testimony and schedules, that the third prong of the test was satisfied because the Company routinely makes

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[26] *Cause No. 45235*, Final Order p. 62.
[27] *Id*.
[28] *In re PSI Energy, Inc.*, Cause No. 42359, Final Order, p. 89 (Ind. Util. Regul. Comm'n May 18, 2004) ("Cause No. 42359"); *see also*, *In re S. Ind. Gas and Elec. Co., d/b/a Vectren Energy Delivery of Ind. Inc.*, Cause No. 43839, Final Order, p. 50 (Ind. Util. Regul. Comm'n Apr. 27, 2011).
[29] *Cause No. 45235*, pp. 62-63.
[30] *Id*. at 62.
[31] *Id.* at 63.

incentive payments in excess of target, and the costs in excess of target are not included in rates but instead are allocated to shareholders.[32]

Q: PLEASE EXPLAIN WHY ALLOCATING ABOVE-TARGET COMPENSATION TO SHAREHOLDERS IS NOT ACTUALLY A SHARING OF RECOVERABLE COSTS.

A: In the last rate case the Company compared *target* compensation levels to market medians to show that the Company's *target* levels of compensation (base pay plus target incentives) were in line with market-based compensation.[33] Mr. Carlin's rebuttal testimony stated:

> Indeed, the ***target*** level of the total compensation I&M offers employees is near the market median on average and generally within the market-competitive range. This is shown on Attachments ARC-2R, ARC-3R, ARC-4R and ARC-SR.[34]
>
> The Company's incentive compensation is not a "bonus" provided on top of already market-competitive compensation. Instead, the ***target compensation*** opportunity that short-term and long-term incentive compensation provide is merely a portion of a reasonable and market-competitive total compensation package that is at risk. Incentive compensation ***targets*** are designed to provide a needed compensation opportunity that, when it is combined with base pay, brings employee total compensation to a reasonable and market-competitive level.[35]

Although the Company asserted that *total* compensation is reasonable and market-based, the data provided to the Commission in the last case only compared *target* compensation levels to market medians. Thus, the evidence showed that the Company's *target* levels are reasonable compared market medians, but it did not show that the payments in excess of

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[32] *Id.*
[33] Cause No. 45235, Petitioner's Ex. 40, Andrew Carlin Rebuttal, pp. 13-15, and Attachments ARC-3R, ARC-4R and ARC-5-R.
[34] *Id.* at 11, lines 16-18 (emphasis added).
[35] *Id.* at 14, lines 16-22 (emphasis added).

target are reasonable or necessary.

Q: DOES THE COMPANY HAVE A HISTORY OF PAYING INCENTIVE COMPENSATION SIGNIFICANTLY IN EXCESS OF TARGET LEVELS?

A: Yes. In the prior rate case, the Company presented a five-year history of incentive compensation payouts, which showed the average payout was more than 150% of target, and had been as high as 191% of target, as reflected in Figure MG-1.[36]

Figure MG-1

Year	Overall AEP Score (As a Percent of Target)
2014	182.7%
2015	191.0%
2016	170.5%
2017	92.0%
2018	144.9%
5-Year Average	**156.2%**

The Company argued that the third prong of the Commission's test was satisfied because "the Company's shareholders have paid and will continue to pay the above-target portion of both annual and long-term incentive compensation, which has been a substantial portion of total incentive compensation expense."[37]

Q: DO YOU BELIEVE THAT A PATTERN OF PAYING SIGNIFICANTLY ABOVE-TARGET COMPENSATION TO UTILITY EMPLOYEES IS REASONABLE AND NECESSARY FOR THE PROVISION OF ELECTRIC SERVICE?

[36] *See Cause No. 45235*, p. 63 (citing Petitioner's Ex. 40, Andrew Carlin Rebuttal, at p. 18).
[37] *Id.*, Petitioner's Ex. 40, Andrew Carlin Rebuttal, at p. 18, line 8—19, line 2.

A: No. I believe the Company's data only suggested that its *target* compensation levels were reasonable. As such, while it is appropriate that the above-target compensation amounts are excluded from rates, in accordance with the second prong of the Commission's standard, it does not accomplish a true *sharing* of the market-based, reasonable and necessary costs. The purpose of the benchmarking data provided by regulated utilities is to show that the target compensation levels are in line with the market.

When the Company's incentive compensation plans routinely cause payouts significantly *above* target, it is a cause for concern. In the competitive market, employers strive to pay market-based compensation, but can rarely afford to pay compensation that is significantly above market. As the surrogate for competition for monopoly utilities, regulators establish policies (such as the Commission's three-pronged test) to ensure that utility compensation levels are reasonable and necessary for the provision of service. As shown herein, there are indications that I&M's plans in this proceeding are not fully in line with the Commission's standard, and that a sharing of a portion of the *target* level of compensation would be appropriate under the circumstances.

Q: DOES THE COMPANY'S APPROACH SATISFY THE THREE COMPONENTS OF THE COMMISSION'S STANDARD?

A: I do not believe that the Company's approach fully complies with the Commission's three-pronged standard. More specifically, I respectfully disagree that allocating the above-target portion of the incentive compensation plan costs to shareholders constitutes a legitimate *sharing* of costs between shareholders and ratepayers. As discussed in the section below, I believe that the removal of above-target costs is required by the *second* prong of the test—which ensures that above-market incentive plan costs are not recovered in rates. If removal of the above-target costs were the only adjustment required to satisfy the Commission's standard, the third prong would be unnecessary. For this reason, I contend that the third prong of the Commission's test requires a *sharing* of the market-based (*target)* level incentive compensation costs, in recognition of the fact that the incentive compensation plan provides benefits to shareholders and ratepayers alike.

Q: ARE YOU AWARE OF A PROCEEDING IN WHICH THE COMMISSION APPROVED A 50%-50% SHARING OF THE UTILITY'S TARGET LEVEL OF INCENTIVE COMPENSATION EXPENSE?

A: Yes. The Commission addressed this treatment in *NIPSCO*, Cause No. 43526, p. 63. In that case, the Industrial Group witness proposed to disallow all of NIPSCO's incentive plan costs based on the existence of a financial trigger, however, the Commission determined that an equal sharing of the *target* level of incentive compensation expense was the appropriate treatment. The Commission's order states:

> Under our criteria, once an incentive compensation plan is found to provide benefits to shareholders and ratepayers and not be excessive, an appropriate level of costs should be recovered from ratepayers who are benefited by these programs. Mr. Campbell explained that NiSource's shareholders are already allocated a portion of the incentive plan costs ***because NIPSCO's adjustment only includes incentive compensation at the trigger level which is 50% below the target amount, leaving shareholders to cover the target and stretch levels***. Thus, NIPSCO's adjustment reduces electric test year incentive compensation expense by $916,264.[38]

[38] *In re N. Ind. Pub. Serv. Co.*, ("NIPSCO"), Cause No. 43526, Final Order, p. 63 (Ind. Util. Regul. Comm'n Aug. 25, 2010) ("Cause No. 43526") (emphasis added).

Q: IS THE *NIPSCO* TREATMENT OF INCENTIVE PAY DIFFERENT THAN THE TREATMENT APPROVED IN THE LAST I&M RATE CASE, CAUSE NO. 45235?

A: Yes. In *NIPSCO*, the Commission found that the sharing was appropriate because the amount included in rates was 50% *below* the target level (leaving shareholders to cover the target and stretch levels). By contrast, I&M's position is that ratepayers pay for 100% of the target level, leaving shareholders only to cover the stretch levels. The stretch levels are the above-target payouts that have not been compared to market medians, and thus, would not be recoverable under the *second* prong of the test which ensures that above-market incentive plan costs are not recovered in rates. In order to accomplish a legitimate sharing of incentive plan costs—which gives effect to the third prong of the test as the Commission approved in NIPSCO—requires an adjustment to remove 50% of I&M's *target* level incentive compensation costs.

Q: PLEASE DESCRIBE THE COMPANY'S SHORT TERM INCENTIVE COMPENSATION PLANS IN THIS PROCEEDING.

A: For 2020, the earnings component of the annual incentive plan was amended to 100%--thereby making 2020 a pure profit sharing plain. In 2021, the financial goals are currently set to 60% of the Company's incentive compensation plan metrics. The annual earnings per share (EPS) thresholds are based on AEP's EPS targets which have increased each year as shown in the figure below:

Figure MG-2

Year	Earnings Component	EPS Threshold
2020[39]	100%	$4.25 per share
2021[40]	60%	$4.55 per share

AEP's 2020 Annual Incentive Plan states:

> Awards are determined based on AEP's performance and, if applicable, business unit or operating company performance and individual employee performance. For 2020, we changed the way we measure AEP performance to a single goal: **AEP operating earnings per share (Operating EPS) with a 100% weight**. This change simplifies ICP funding for 2020 by focusing it on a single, critical financial objective that will better ensure that we all remain focused on taking the necessary actions to protect and maintain the financial health of the Company, which is in the interests of all stakeholders, including employees. Linking annual incentive compensation to AEP's earnings aligns it with the value employees create each year and ensures that AEP meets its commitments to other stakeholders before setting aside ICP award funding for employees.[41]

This statement shows that the Company changed its 2020 annual incentive plan mid-year out of financial concerns, which illustrates the extent to which the plan is discretionary. Senior management is free to alter the payout levels and formulas in any manner considered necessary to protect shareholders' interests. For this reason, it is appropriate to calculate the sharing of incentive costs between ratepayers and shareholders based upon the *actual* mechanism adopted during the test year.

Q: DOES THE PLAN SPECIFICALLY STATE THAT AEP'S ANNUAL INCENTIVE

[39] See MSFR Vol. 2 of 3, p. 23, 1-5-8(a)(12) Attachment 2, p. 4 of 16.
[40] See MSFR Vol. 2 of 3, p. 19, 1-5-8(a)(12) Attachment 1, p. 3 of 15.
[41] See MSFR Vol. 2 of 3, p. 23, 1-5-8(a)(12) Attachment 2, p. 3 of 16 (emphasis original).

COMPENSATION PLANS ARE DISCRETIONARY AND CONTINGENT ON AEP'S FINANCIAL PERFORMANCE?

A: Yes. AEP's HR Committee may adjust or amend plan funding at its discretion and all funding is contingent on AEP achieving its target operating earnings:

> **Operating Earnings Per Share (100% Weight)**
> AEP is committed to generating sustainable value for all its stakeholders through its earnings and growth. Therefore 100% of annual incentive funding is tied to AEP's Operating EPS. This ensures that funding is commensurate with the Company's operating earnings and the extent to which the company can afford to pay annual incentive compensation while also serving the interests of its shareholders, customers and other stakeholders. It also:
>
> - Aligns employee interests with those of customers by strongly encouraging expense discipline,
>
> - ***Ensures that adequate earnings are generated for AEP's shareholders and continued investment in AEP's business before setting aside annual incentive compensation for employees***, and
>
> - Further aligns the financial interests of all AEP employees with the results employees deliver to the Company and all its stakeholders.
>
> In the event that AEP's Operating EPS is less than the $4.25 threshold for 2020, then no incentive awards will be paid under the Plan. Operating EPS must reach threshold for any payout to occur.[42]

For 2020, the funding for I&M's plan was purely profit based, with 100% weight given to the single goal of achieving AEP's EPS threshold of $4.25 per share. This raises questions whether I&M's 2020 plan satisfies the first prong of the Commission's Cause No. 42359 three-prong test, that of whether the incentive compensation plan is "not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals."

[42] See MSFR Vol. 2 of 3, p. 23, 1-5-8(a)(12) Attachment 2, p. 4 of 16 (emphasis added).

Q: DO INCENTIVE PLANS OF THIS NATURE PRIORITIZE THE INTERESTS OF SHAREHOLDERS OVER THE INTERESTS OF CUSTOMERS?

A: Yes. Although the Commission has indicated that it has not been receptive to excluding recovery of those portions of incentive plans tied to financial metrics, it has also indicated that pure profit-sharing plans, which only incent employees to become more profitable, may be more appropriate for funding solely by shareholders.[43] Plans that are heavily weighted on EPS targets prioritize maximizing shareholders' earnings. AEP's plan acknowledges that shareholder earnings are an essential part of the plan. One of its stated reasons for the EPS metric is that it, "ensures that adequate earnings are generated for AEP's shareholders and continued investment in AEP's business *before* setting aside annual incentive compensation for employees."[44] From a ratemaking perspective, this means that money collected from ratepayers for the purpose of paying employee incentives may not be paid to employees if EPS thresholds are not met, but instead may be diverted, if needed, to bolster shareholders' return on investment.

Under the Company's plan, regardless of how well the employees may perform in non-financial or operational performance measures such as safety or customer satisfaction, if the EPS is below the stated threshold, the awards can be reduced to zero. This actually did occur in 2009.[45] Thus, the Company's EPS is the primary controlling factor for whether: (1) the incentive compensation will be paid (the trigger), and (2) to what extent incentives will be paid (the funding).

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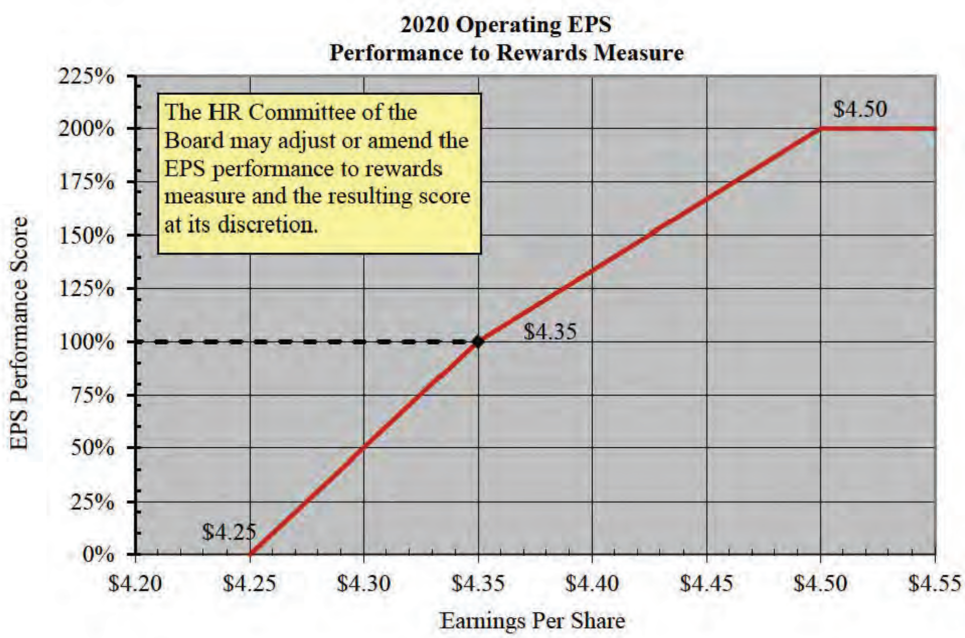
[43] *Cause No. 45235*, p. 62 (*citing In re Ind. American*, Cause No. 42029, p. 45).
[44] See MSFR Vol. 2 of 3, p. 23, 1-5-8(a)(12) Attachment 2, p. 4 of 16 (emphasis added).
[45] See AEP Notice of 2010 Annual Meeting and Proxy Statement, p. 43.

Q: HOW DOES AEP'S FUNDING MECHANISM WORK?

A: The funding of the plan goes beyond a mere trigger. It provides for ***increasing*** levels of funding for employee incentives based on AEP's achievement of ***higher*** earnings levels

Figure MG-3[46]



For 2020, the EPS target is $4.35, and for 2021, the EPS target is increased to $4.55. For each year, if AEP achieves its annual EPS target, incentive compensation is awarded. If higher EPS levels are achieved, the plan payout increases up to 200% of target.

Q: PLEASE DESCRIBE AN EXAMPLE OF HOW FINANCIAL INCENTIVES MAY NOT ALIGN WITH CUSTOMER'S INTERESTS.

A: In AEP's 2021 plan, there are specific financially-based performance measures ***in addition***

[46] Figure MG-3 is excerpted from AEP's 2020 Annual Incentive Compensation Plan. MSFR 1-5-8(a)-12 Attachment 2, p. 5 of 16.

to the 60% EPS metric. AEP's annual incentive funding is tied to Operating Earnings per Share (60% weight), safety and compliance (10% weight) and strategic initiatives (30% weight). The "strategic initiatives" category contains a combination of operational and financial-based performance measures. Of specific concern is the sub-category "Infrastructure Investment", which makes up 16% of AEP's funding plan for 2021. Within this category, AEP sets specific target ***spending goals*** for transmission infrastructure and capital investment. In other words, the ***more*** the Company spends, the greater the incentive compensation funding available for employees.[47]

This portion of the plan is designed to maximize shareholder earnings. If AEP's transmission infrastructure investment spending is below the threshold level of **$2.815 billion**, there is 0% payout for this metric. If AEP meets the transmission infrastructure target of **$3.082 billion**, the Plan is funded at 100% payout level, and if the maximum target of **$3.182 billion** is achieved, the Plan is funded at 200% payout level. The concern with an incentive of this type is that it creates ***improper motivation*** to maximize investments where they may not be needed, to replace assets early, or to gold-plate the system to meet target spending levels. This metric may help increase shareholder earnings and employee incentives, but it is not designed to protect ratepayers' interests.

Q: IS THERE EVIDENCE THAT AEP'S SHAREHOLDERS ARE BENEFITTING SIGNIFICANTLY FROM THE COMPANY'S FOCUS ON EPS AS A MEASURE

[47] The Transmission Infrastructure metric is excerpted from MSFR Vol. 2 of 3, 1-5-8(a)(12) Attachment 1, pp. 5-6 of 13.

OF EMPLOYEE INCENTIVE COMPENSATION?

A: Yes. By maintaining a heavily financial based incentive compensation plan, AEP creates incentives for its employees (especially upper management) to find ways to spend more in order to increase their own compensation levels, as seen with the plans' Infrastructure Investment goals (discussed above). In my opinion, it is not appropriate for a monopoly public utility with a defined service territory to place such undue emphasis on increasing its earnings per share every year. As seen in Figure MG-4 below, AEP's target EPS has increased substantially over the past decade:[48]

Figure MG-4

AEP Operating EPS Threshold 2010-2021	
Year	EPS Threshold
2010	$2.80
2011	$3.00
2012	$3.00
2013	$3.00
2014	$3.15
2015	$3.35
2016	$3.65
2017	$3.55
2018	$3.70
2019	$3.95
2020	$4.25
2021	$4.55

As shown in the table above AEP's Operating EPS threshold has increased from $2.80 in 2010 to $4.55 in 2021, an increase of 63% over the past eleven years. Even during the

[48] See Attachment MG-5 for a copy of SWEPCO's (Arkansas) Response to AG 4-2, showing AEP's Operating EPS threshold for 2010 through 2018. Source: Docket No. 19-008-U, Ark. Pub. Serv. Comm'n. For 2019 EPS threshold, see 2020 Notice of Annual Meeting and Proxy Statement, p. 40. For 2020 EPS threshold, see MSFR Vol. 2 of 3, p. 23, 1-5-8(a)(12) Attachment 2, p. 4 of 16; for 2021, see MSFR Vol. 2 of 3, p. 19, 1-5-8(a)(12) Attachment 1, p. 3 of 15.

height of the Covid-19 economy, when many companies and customers faced economic hardship and loss of businesses, AEP sought to ensure that its shareholders were protected and received a significant increase over its prior years' earnings levels.

Q: ARE AEP'S EPS THRESHOLD REQUIREMENTS STANDARDIZED ACROSS ALL THE JURISDICTIONS IN WHICH ITS SUBSIDIARY UTILITY COMPANIES OPERATE?

A: Yes. The annual operating EPS threshold portion of AEP's incentive compensation plans apply company-wide across all jurisdictions in which AEP's operating companies provide service.

Q: ARE YOU FAMILIAR WITH THE REGULATORY TREATMENT OF AEP'S ANNUAL INCENTIVE COMPENSATION PLANS IN OTHER JURISDICTIONS?

A: Yes. I have testified in numerous regulatory proceedings involving AEP's annual incentive compensation plans related to Public Service Company of Oklahoma ("PSO") in Oklahoma, and Southwestern Electric Power Company ("SWEPCO") in Texas and Arkansas. In these jurisdictions, the portion of incentive compensation included in rates always excludes above-target compensation levels. In calculating the portion of incentive compensation to be included in rates, the Company's total incentive compensation level is first adjusted down to *target*, and then, the target level compensation is further adjusted in accordance with the regulatory commission's applicable sharing ratio.

Q: WHY IS IT IMPORTANT TO CONSIDER THE REGULATORY TREATMENT OF INCENTIVE COMPENSATION IN OTHER JURISDICTIONS IN WHICH AEP'S SUBSIDIARY UTILITY COMPANIES OPERATE?

A: Because AEP's annual EPS threshold and payout mechanism is standardized across all of its operating companies, the manner in which regulators in other states adjust AEP's incentive compensation is relevant to show that I&M would not be placed at a competitive disadvantage if the Commission were to adopt a sharing of the *target* level incentives as I recommend. My overarching goal is to ensure that customers receive safe, reliable service at the lowest reasonable cost. In my experience, this can be accomplished through a sharing of *target* level incentive compensation between shareholders and ratepayers. Full recovery of target level of incentives is not required, and for many years has not been approved for I&M's sister companies PSO and SWEPCO. For many years, the Oklahoma Corporation Commission ("OCC") has allocated target level incentive costs 50%-50% between shareholders and ratepayers.[49] Similarly, the Arkansas Public Service Commission ("APSC") has routinely required I&M's sister company SWEPCO to allocate the costs of target level incentives equally between shareholders and ratepayers.[50]

The Public Utility Commission of Texas' ("PUCT") policy is more stringent. It has a longstanding policy of disallowing 100% of annual incentives ***directly*** tied to financial performance measures, and in addition, disallows 50% of the remaining

[49] *See* Final Orders in *In re Pub. Serv. Co. of Okla.*, Cause No. PUD 200600285 (Okla. Corp. Comm'n Oct. 9, 2007); *In re Pub. Serv. Co. of Okla.*, Cause No. PUD 200800144, p. 21 (Okla. Corp. Comm'n Feb. 14, 2009); *In re Pub. Serv. Co. of Okla.*, Cause No. PUD 201500208, p. 161 (Okla. Corp. Comm'n Nov. 10, 2016); and *In re Pub. Serv. Co. of Okla.*, Cause No. PUD 201700151, p. 57 (Okla. Corp. Comm'n Jan. 31, 2018).
[50] *In re Entergy Ark. Inc.*, Cause No. 13-028-U, Order No. 21, p. 54 (Ark. Pub. Serv. Comm'n Dec. 30, 2013) and *In re Sourcegas Ark. Inc.*, Docket No. 15-011-U, Order No. 10, p. 22, (Ark. Pub. Serv. Comm'n Jan. 28, 2016).

incentives if they are ***indirectly*** tied to financial performance through an EPS funding mechanism.[51] In applying this approach to AEP-SWEPCO's plan, the PUCT requires three adjustments:

1) Adjust incentive plan costs to *target* level;
2) Remove costs *directly* tied to financial performance measures;
3) Remove 50% of costs *indirectly* tied to financial performance through the EPS trigger and funding mechanism.

Q: UTILITIES OFTEN CLAIM INCENTIVE COMPENSATION PROGRAMS ARE NECESSARY TO ATTRACT AND RETAIN QUALIFIED PERSONNEL TO PROVIDE SAFE AND RELIABLE SERVICE. DO YOU AGREE?

A: No. Utilities often claim their incentive compensation plans are necessary for attracting talent to provide safe and reliable service. However, much of the electricity in this country is provided by municipal electric providers that do not pay short-term incentives, yet they are able to attract talent sufficient to deliver safe and reliable service.[52] Electric cooperatives also provide a substantial amount of the electricity used in this country but many do so without the use of short-term incentives.[53] Likewise, many state-run electric systems also provide electric service without the use of short-term incentives,[54] as do some federally-owned utilities.[55] So, it is inaccurate to say that incentives are ***necessary*** for the provision of electric service.

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[51] *See App. of S.W. Pub. Serv. Co.*, Docket No. 43695, Order on Rehearing at pp. 5-6 (Tex. Pub. Util. Comm'n Feb. 23, 2016). *Also see*, *Pet. of AEP Tex. Cent. Co.*, Docket No. 46495 (Tex. Pub. Util. Comm'n Jan. 12, 2017), and *App. of S.W. Pub. Serv. Co.*, Docket No. 46449 (Tex. Pub. Util. Comm'n Jan. 11, 2018).
[52] *See e.g.*, Attachment MG-6, Oklahoma Docket No. PUD 2018-00140, OG&E response to OIEC 9-8.
[53] *Id.*
[54] *Id.*
[55] *Id.*

The other problem with this argument is that it does nothing to explain why incentive pay should be included in rates. Virtually all utilities have the same need to attract qualified employees, but many of these other utilities are ***not recovering*** the full amount of their incentive pay in rates.

Q: ARE YOU RECOMMENDING THAT THE COMPANY ELIMINATE ITS SHORT-TERM INCENTIVES?

A: No. The question for ratemaking purposes is not whether the utility should offer short-term incentives to its employees; the question is, who should pay for them. My point is that the metrics of many incentive compensation plans (like AEP's plan in this case) are primarily designed to increase shareholder wealth rather than to enhance the provision of safe and reliable electric service. The consensus view is that financial-based incentives benefit the shareholders more than they do the ratepayers, and, as a result, should be paid for by the shareholders. This point was addressed recently by the Wisconsin commission:

> [T]he Commission is not persuaded by NSPW's arguments that its overall compensation without the AIP would fall below market rates. The Commission is also not persuaded by NSPW's argument that recovery of the AIP expense from ratepayers is required in order for NSPW to attract and compete for employees. NSPW provided no evidence of any unsuccessful recruitments or other examples of any difficulty in hiring talented employees because NSPW is not recovering its AIP payments in rates. *NSPW's management is not prohibited from paying a portion of its overall 2018 employee compensation in the form of incentives*. However, the amount of payroll expense authorized for recovery is limited to what the Commission has determined to be reasonable in this case.[56]

[56] *In re Northern States Power Co.*, Docket No. 4220-UR-123, Final Order, p. 16 (Wisc. Pub. Serv. Comm'n Dec. 21, 2017).

Q: WHAT ARE YOU RECOMMENDING WITH RESPECT TO THE COMPANY'S INCENTIVE EXPENSE?

A: First, the Company's 2020 plan is purely a profit-sharing plan since 100% of the funding is tied to achieving AEP's target operating EPS. Second, the Company's 2021 plan is ***strongly tied*** to metrics that incentivize capital investment ***spending*** targets, which clearly benefit shareholders but may not be in customers' best interests. Most importantly, by only allocating the above-target costs to shareholders, I&M's plan does not satisfy the third prong of the Commission's test, and therefore does not satisfy the Commission's standard for full recovery of the target level compensation.

For these reasons, I recommend the Commission adopt a ***50% - 50% sharing approach*** which allocates the *target* level of annual incentive plan costs evenly between shareholders and ratepayers. A 50% -50% sharing approach is a reasonable approach that recognizes the Company's plan is based on both financial and operational performance measures, and that it benefits both shareholders and ratepayers. The calculations supporting this adjustment are set forth at Schedule MG-12.

Adjustment to Remove 50% of Annual Incentive Costs

Adjustment to Remove 50% of O&M Expense	$(8,031,687)
Adjustment to Reduce Related Payroll Tax Expense	$ (614,424)
Adjustment to Rate Base for Capitalized Incentives	$(3,350,590)

II. C. LONG-TERM EXECUTIVE STOCK INCENTIVE PLAN

Q: WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO THE RECOVERY OF LONG-TERM STOCK INCENTIVE PLAN FOR EXECUTIVES?

A: The Company seeks to recover long-term incentive plan expense of $7,926,490, which is

$5,640,187 to the Indiana jurisdiction.[57]

Q: PLEASE DESCRIBE THE COMPANY'S LONG-TERM COMPENSATION PLANS.

A: In addition to the Company-wide incentive plans discussed above, executives and managers of the Company are provided Long-Term Incentive Plan ("LTIP") compensation.[58] The LTIP awards are composed of *performance units* and *restricted stock units* (RSUs). The performance units are granted based on three performance measures: three-year total shareholder return (40%), and three-year cumulative operating EPS which is measured relative to a target set by AEP's board of directors (50%), and three-year non-emitting generating capacity growth (10%).[59]

Q: WHAT IS THE RATIONALE FOR EXCLUDING LONG-TERM INCENTIVE COMPENSATION EXPENSE?

A: Long term incentives, especially stock-based incentives such as AEP's, are financial-based incentives and should be disallowed for all of the reasons set forth in the previous section. Incentive compensation payments to officers, executives, and key employees of a utility, such as the long-term incentive payments, are generally excluded for ratemaking purposes. Officers of any corporation have a fiduciary duty to the corporation to put the interests of the company first. Undoubtedly, the interests of the company and the interests of the

[57] See Attachment MG-7, OUCC DR 5-2 Attachment 1.
[58] MSFR: 1-5-8(a)-12 Attachment 3, p. 5 of 28.
[59] AEP's 2021 Notice of Annual Meeting and Proxy Statement, p. 42.

customer are not always the same, and at times, can be quite divergent. This natural divergence of interests creates a situation where not every cost associated with executive compensation is presumed to be a necessary cost of providing utility service. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs would be better borne by the utility shareholders.

It has been my experience that some utilities treat long-term executive incentive compensation costs as a below-the-line item even without a Commission order directing them to do so. Further, long-term incentive plans are specifically designed to tie compensation to the financial performance of the company. This is done to further align the interest of the employee with those of the shareholder. Since the compensation of the employee is tied over a long period of time to the company's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of the shareholders first.

Q: HOW HAS THIS COMMISSION ADDRESSED THE RATEMAKING TREATMENT OF LONG TERM INCENTIVE COMPENSATION PREVIOUSLY?

A: In I&M's last rate case, the Commission allowed recovery of I&M's long term incentive compensation, because it found that I&M's LTIP was not reserved for high level management positions, and because I&M's plan included restricted stock units that are intended to encourage retention.[60]

Q: IN THE CURRENT ECONOMIC CLIMATE, DO YOU BELIEVE IT IS APPROPRIATE FOR I&M TO RECEIVE A FULL RECOVERY OF ITS LONG TERM INCENTIVE COMPENSATION?

A: No. Long term incentive compensation is designed to align the interests of employees with the interests of the shareholders. AEP's management decision to modify its short-term incentive compensation to a 100% profit-sharing plan due to the Covid-19 crisis raises concerns that the Company management's interests are too closely aligned with shareholders' interests and insufficiently sensitive to the hardships faced by customers. At a time when individuals and businesses are struggling to make ends meet, it is important for regulators to impose cost constraint measures on the utility company as well.

For these reasons, I recommend that the Commission reconsider its decision with respect to LTIP expense, and apply the standard previously approved in its 2012 Indiana-American Water Company, Inc., Cause No. 44022 which held that financially-based long-term incentives should be excluded for ratemaking purposes:

> LTIP is based on the total shareholder return and internal performance goals. Although the LTIP is not a pure profit-sharing plan, *it is strongly tied to financial performance* in that the Board of Directors determines the level of additional compensation. In addition, the Commission notes that given the current economic climate and the other increases being requested by Petitioner in this

[60] *Cause No. 45235*, p. 63.

> case, it is reasonable for Petitioner to mitigate rate increases and control costs where possible. Therefore, we find that Petitioner's *LTIP expense should be borne by its shareholders rather than its ratepayers, and we disallow the pro forma LTIP expense*.[61]

Q: HOW IS LONG-TERM INCENTIVE COMPENSATION TREATED IN OTHER JURISDICTIONS?

A: In my experience, most states follow the general rule that incentive pay associated with financial performance is not allowed in rates. This means that recovery of long-term, stock-based incentives are not allowed in most states.

Q: WHEN UTILITIES SEEK TO RECOVER LONG-TERM INCENTIVE COMPENSATION IN RATES, WHAT RATIONALE IS GENERALLY PROVIDED?

A: Generally, utilities argue that long-term incentives are part of an overall compensation package that is designed to attract and retain qualified personnel. Since other utilities offer incentive plans to their executives, a company would run the risk of not being able to compete for key personnel if it did not offer a comparable plan.

Q: IS THIS ARGUMENT PLAUSIBLE?

A: No. The problem with the Company's argument is that when utilities, such as AEP, compete with other utilities for qualified executives, and the long-term incentive

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[61] *In re Indiana-American Water Co.*, Cause No. 44022, Final Order, p. 57 (Ind. Util. Regul. Comm'n Jun. 6, 2012) ("Cause No. 44022") (emphasis added).

compensation plans of those other utilities are not being recovered through rates, AEP is not placed at a competitive disadvantage when its long-term incentive compensation is excluded as well. The fact that other utilities offer long-term incentive plans is not relevant; what is relevant is the fact that other utilities are not recovering the costs of those plans in rates. In an order disallowing Nevada Power's long-term incentive plan, the Nevada Commission articulated this important ratemaking concept as follows:

> Therefore, the Commission accepts BCP's and SNHG's recommendations to disallow recovery of expenses associated with LTIP. Both parties provide a valid argument that this type of incentive plan is mainly for the benefit of shareholders. Further, both BCP and SNHG provide examples of numerous other jurisdictions that do not allow the recovery of these costs and, *therefore, disallowance in this instance would not place NPC in a competitive disadvantage*.[62]

Further, the problem with the "total compensation package" argument is that when an incentive payment is paid based on the achievement of financial performance goals, there should be sufficient financial benefit to the company as the result of achieving these goals. This financial benefit should provide ample additional funds from which to make the incentive payments. If not, the plan was poorly conceived. Thus, a utility is not placed at a competitive disadvantage when incentive payments tied to financial performance are not collected through rates, because the funding for these payments should come out of the additional earnings the incentive plans help achieve.

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[62] *See In re Nevada Power Co.*, Docket No. 08-12002, Final Order, p. 139, ¶549, (Nev. Pub. Util. Comm'n Jun. 24, 2009) (emphasis added).

Q: WHAT OTHER RATIONALE DO UTILITIES TYPICALLY PROVIDE FOR INCLUDING LONG-TERM STOCK-BASED INCENTIVES IN RATES?

A: Companies claim that long-term incentives are *necessary* costs, and, as such, they should be included in rates. But, as discussed previously in my testimony, when tested, this assertion does not prove to be true. As discussed earlier in this testimony, much of the electricity in this country is provided by *municipal electric providers* virtually none of which pay long-term stock-based incentives, yet they are able to attract talent sufficient to deliver safe and reliable electric service.[63] *Electric cooperatives* also provide a substantial amount of the electricity used in this country but do so without the use of long-term stock-based incentives.[64] Likewise, *state-run electric systems* provide electric service without the use of long-term incentives,[65] as do *federally-owned utilities*.[66] So, if municipalities, cooperatives, state and federally-run electric systems can provide electric service without the use of long-term incentive compensation, I believe it is inaccurate to say that long-term incentives are *necessary* for the provision of electric service.

Q: WHAT IS THE IMPACT OF YOUR ADJUSTMENT TO EXCLUDE THE COMPANY'S LONG-TERM STOCK INCENTIVE PLAN COSTS?

A: My adjustment removes 100% of the long-term incentive plan costs included in pro forma operating expense in the Indiana jurisdiction and 100% of the capitalized long-term

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[63] See Attachment MG-6, *In re Oklahoma Gas & Elec.* ("OG&E"), Cause No. PUD 201800140 (Okla. Pub. Util. Comm'n), OG&E response to OIEC 9-8 by Michael Halloran, Senior Partner at Mercer (US) Inc., a firm specializing in employee compensation issues.
[64] *Id.*
[65] *Id.*
[66] *Id.*

incentives. The calculations supporting this adjustment are set forth at Schedule MG-13.

Adjustment to Remove 100% of Long-Term Incentive Costs

Adjustment to Remove 100% of O&M Expense	$(5,640,187)
Adjustment to Rate Base for Capitalized Long-Term Incentives	$(1,875,926)

II. D. NON-QUALIFIED SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS

Q: PLEASE DESCRIBE THE SUPPLEMENTAL EMPLOYEE PENSION PLAN.

A: The Company provides supplemental retirement plan benefits to certain highly-compensated individuals at the Company. These supplemental retirement plans for highly compensated individuals are provided because benefits under the general retirement plans are subject to limitations under the Internal Revenue Code. Benefits payable under these supplemental plans are typically equivalent to the amounts that would have been paid but for the limitations imposed by the Code. In general, the limitations imposed by the Code allow for the computation of benefits on annual compensation levels of up to $285,000 for 2020 and $290,000 for 2021. Retirement benefits on compensation levels in excess of annual compensation limits are paid through supplemental plans. Thus, supplemental retirement plans for highly compensated employees are designed to provide benefits in addition to the benefits provided under the general pension plans of the company. These plans are referred to as *non-qualified* plans because they do not qualify as a deductible tax expense under the code.

Q: WHAT AMOUNTS WERE INCLUDED IN PRO FORMA OPERATING EXPENSE FOR THE SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS?

A: The Company included $212,972 of non-qualified plan costs in its in pro forma operating expense for ratemaking purposes in the Company's application.[67]

Q: WHAT DO YOU RECOMMEND WITH RESPECT TO SUPPLEMENTAL NON-QUALIFYING COSTS FOR HIGHLY COMPENSATED EMPLOYEES?

A: I recommend that supplemental costs be disallowed as a matter of principle. If these supplemental costs are disallowed, ratepayers will pay for all of the executive benefits included in the Company's regular pension plans, and shareholders will pay for the additional executive benefits included in the supplemental plan. For ratemaking purposes, shareholders should bear the additional costs associated with supplemental benefits to highly compensated executives, since these costs are not necessary for the provision of utility service but are instead discretionary costs of the shareholders designed to attract, retain and reward highly compensated employees. Further, because officers of any corporation have a duty of loyalty and duty of care to the corporation, these individuals are required to put the interest of the company first. This creates a situation where not every cost associated with executive compensation is presumed to be a cost appropriately passed on to ratepayers. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs would be better borne by the utility shareholders.

[67] See MSFR 1-5-8(a)(13) Projected, line 12 allocated, plus line 15 ($133,000*(1-(4,117/(15,499+133))+$115,000 = $212,972).

Q: HOW HAS SUPPLEMENTAL RETIREMENT PAY BEEN TREATED IN OTHER JURISDICTIONS?

A: Most states disallow recovery of supplemental retirement expense, as these amounts are not considered necessary for the provision of utility services. For instance, the Texas commission has consistently disallowed SWEPCO's supplemental retirement costs. In Docket No. 46449, the Texas PUC denied SWEPCO's request for recovery of non-qualified supplemental executive compensation costs, finding:

> 203. SWEPCO's non-qualified supplemental executive retirement plans are *discretionary costs* designed to attract, retain, and reward highly compensated employees *whose interests are more closely aligned with those of the shareholders than the customers*.
>
> 204. SWEPCO's requested non-qualified supplemental executive retirement benefits *are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in SWEPCO's cost of service*.[68]

In Oklahoma, the OCC has consistently disallowed 100% of AEP-PSO's supplemental retirement pay.[69] In PSO's 2017 rate case, Cause No. PUD 201700151, the Commission continued its longstanding policy of disallowing PSO's supplemental retirement plan costs.

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[68] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 46449, Findings of Fact Nos. 202-204, Order on Rehearing, p. 34 (Tex. Pub. Util. Comm'n Mar. 19, 2018) (emphasis added).
[69] In every rate case since 2006, the OCC has disallowed 100% of AEP-PSO's SERP expense. *See In re Pub. Serv. Co. of Okla.*, Cause No. PUD 200600285 (Okla. Corp. Comm'n Oct. 9, 2007); *In re Pub. Serv. Co. of Okla.,* Cause No. PUD 200800144, p. 21 (Okla. Corp. Comm'n Feb. 14, 2009), *In re Pub. Serv. Co. of Okla.,* Cause No. PUD 201500208, p. 161 (Okla. Corp. Comm'n Nov. 10, 2016); and *In re Pub. Serv. Co. of Okla.,* Cause No. PUD 201700151, p. 57 (Okla. Corp. Comm'n Jan. 31, 2018).

> **Supplemental Executive Retirement Plan ("SERP")**
>
> 79. [t]he Commission finds that for rate-making purposes, utility shareholders should bear the additional costs associated with supplemental benefits to executives.
>
> 80. THE COMMISSION FURTHER FINDS and disallows SERP costs in this Cause based on the premise that ratepayers should pay for all of the executive benefits included in the Company's regular pension plans while shareholders should pay for the additional benefits included in the supplemental plan. . .Therefore, the Commission finds that SERP expense in the amount of $96,780.00 for PSO and $253,082.00 for AEPSC are excluded from PSO's rates.[70]

Q: WHAT ADJUSTMENT ARE YOU RECOMMENDING?

A: The impact of this adjustment to the Indiana jurisdiction is set forth below and is shown at Schedule MG-14.

Adjustment to Remove Supplemental Retirement Plan Expense	$(151,543)

II. E. FULL TIME EMPLOYEE ("FTE") UNFILLED POSITIONS

Q: PLEASE DISCUSS THE PAYROLL EXPENSE PROJECTED FOR THE TEST YEAR.

A: The Company projected a payroll cost of $288.5 million for the 2022 test year which includes the base payroll and overtime for I&M and AEPSC. The Company projected that $192.6 million, or 66.76% of that cost would be included in O&M expenses.[71] I&M direct base pay and overtime accounted for $211.8 million of the total base pay and overtime

[70] *In re Pub. Serv. Co. of Okla.*, Cause No. PUD 201700151 (Okla. Corp. Comm'n Jan. 31, 2018)
[71] See Attachment MG-8, OUCC DR 6-1, Attachment 1.

payroll based on 2,105 *authorized* positions. *Authorized* positions include both vacant and open positions.[72]

Q: IS THERE ANY CERTAINTY THAT I&M WILL FILL THE VACANT AND OPEN POSITIONS THAT ARE INCLUDED IN THE TEST YEAR COSTS?

A: No. In fact, given I&M's history with having unfilled budgeted positions, it is very unlikely that these positions will be filled. This is expected, to some extent, because it is fairly common for a large employer to have a number of vacant positions open at all times due to employee turnover. The figure below shows the budgeted and average actual number of employees of I&M for the years 2016 through 2020.[73]

Figure MG-5

I&M Budgeted and Actual Average Employee Counts			
Year	Budgeted Positions	Average Employees	Unfilled Positions
2016	2301	2230	71
2017	2329	2212	117
2018	2336	2199	137
2019	2305	2165	140
2020	2348	2110	238
5-YR Average			140.6

The unfilled positions for I&M ranged from 71 in 2016 to 238 in 2020, for an average of 140.6 unfilled positions during the five-year period.

[72] See Attachment MG-9, OUCC DR 6-3, Attachment 1.
[73] See Attachment MG-10, OUCC DR 6-4, Attachment 1 for the average employees and Attachment MG-11,OUCC DR 6-5, Attachment 1 for the budgeted employees.

Q: THE FIGURE ABOVE ALSO SHOWS THAT THE ACTUAL EMPLOYEE LEVELS HAVE DECLINED ANNUALLY OVER THE PAST FIVE YEARS AT I&M. HAS THAT TREND CONTINUED IN 2021?

A: Yes. The data for the first six months of 2021 shows that the trend of reducing actual employee count at I&M has continued during 2021.[74]

Figure MG-6

I&M 2021 Employee Counts by Month	
Jan	2051
Feb	2047
Mar	2025
Apr	2014
May	2019
June	2032

Based on this information, it is reasonable to conclude that I&M will continue to have unfilled positions and will not fill the projected 2,105 authorized positions in 2022. I&M was already 73 employees below its 2022 budgeted level as of June 2021 with a year and a half of attrition left before the end of the test year.

Q: WHAT IS YOUR RECOMMENDATION REGARDING I&M'S DECLINING EMPLOYEE LEVELS AND VACANT POSITIONS?

A: I recommend that the budgeted payroll cost be reduced by 140.6 positions, which is the average number of vacant positions in the five-year period 2016 through 2020.

Q: WHAT IS THE AMOUNT OF YOUR PROPOSED ADJUSTMENT?

[74] See Attachment MG-12, OUCC DR 6-2 Attachment 1.

A: My adjustment reduces total Company O&M expenses by $10,559,874, or $7,514,007 for the Indiana jurisdiction.

Q: WILL THE EXCLUSION OF PAYROLL FOR VACANT POSITIONS AFFECT PAYROLL TAX EXPENSE?

A: Yes. The adjustment to wages and salaries will reduce Total Company payroll tax liability by $807,830 and $574,822 for the Indiana jurisdiction.

Q: WILL THE EXCLUSION OF VACANT POSITIONS AFFECT PENSION AND BENEFITS EXPENSE?

A: Yes. One hundred forty-one vacant positions represent a 6.7% reduction in the number of employees that will require pensions and benefits. However, I&M over-budgeted those costs by a greater amount than that, so I recommend an appropriate adjustment to those costs later in my testimony.

II. F. EMPLOYEE BENEFITS

Q: PLEASE DESCRIBE THE EMPLOYEE BENEFIT INCREASE PROPOSED BY I&M.

A: I&M requested a significant increase in employee pension and benefits expenses from $18.1 million in 2020[75] to $21.7 million estimated for the test year, a 19.8% increase above the costs for 2020, or 9.4% annually.

[75] See MSFR 1-5-8(a)(13)(A)~(C) Historic, line 29.

Q: ARE THESE INCREASES REASONABLE?

A: No. It is not reasonable to expect this expense to increase at an annual rate of 9.4%. I reviewed the accuracy of I&M's past employee benefit cost projections and found the Company has consistently overestimated this expense over the past five years. I requested I&M's budgeted expenses for the period of 2016 through 2020 and compared those budgeted amounts to the actual expenses reported on its FERC Form 1 report. The results are as follows:

Figure MG-7

I&M Pension and Benefits Expense by Year (Millions)						
	2016	2017	2018	2019	2020	Totals
Budgeted[76]	$ 31.1	$ 32.2	$ 24.1	$ 17.1	$ 22.4	$126.9
Actual[77]	$ 27.4	$ 26.5	$ 16.2	$ 16.8	$ 18.1	$105.0
Difference	$ 3.7	$ 5.7	$ 7.8	$ 0.3	$ 4.2	$ 21.8
% Difference	13.4%	21.7%	48.3%	1.8%	23.4%	20.8%

I&M has overestimated its pension and benefits expense by an average of $5 million per year, or 20% over the last five years.

Q: WHAT OTHER BASIS FOR ESTIMATING THE CHANGE IN THE PENSION AND BENEFITS EXPENSE FROM THE HISTORIC YEAR TO THE TEST YEAR WOULD BE MORE REASONABLE THAN I&M'S PROPOSAL?

[76] See Attachment MG-13, OUCC DR 4-1, Attachment 1.
[77] See Indiana Michigan Power FERC Form 1 reports for 2016 through 2020.

A: The Bureau of Labor Statistics provides a real-world basis for estimating the increase to this expense. I found that the annual increase in pension and benefits expense nationally over the last year was only 2.10%.[78] This would result in a two-year increase of 4.24%.

Q: WHAT IS YOUR RECOMMENDATION FOR I&M'S PENSION AND BENEFITS EXPENSE?

A: I recommend that this expense be limited to an increase of 4.24% increase over the 2020 pension and benefits expense.

Q: WHAT IS THE IMPACT OF THE ADJUSTMENT TO PENSION AND BENEFITS EXPENSE?

A: The adjustment I recommend to pension and benefits expense reduces the I&M requested expense by $2,797,331 on a total company basis, or $1,990,474 for the Indiana jurisdiction. This adjustment can be found on Schedule MG-15.

II. G. PREPAID PENSION AND OPEB ASSETS

Q: PLEASE DISCUSS THE PENSION AND OPEB ASSETS REQUESTED BY I&M.

A: I&M included prepayments in rate base for its pension plans in the amount of $80,675,062[79] and other post-employment benefits ("OPEB") in the amount of $96,252,892[80] for a total of $176,927,954, or $127,429,283 for the Indiana jurisdiction.[81]

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[78] Bureau of Labor Statistics - Employment Cost Index for Benefits - June 2021 News Release.
[79] See Exhibit A-2, page 2, account Prepaid Pension Benefits (165.0010).
[80] See Exhibit A-2, page 2, account Prepaid OPEB Benefits (165.0035).
[81] See Exhibit A-6, line 7.

Company witness Aaron L. Hill argues that "[f]unding included in the prepaid pension asset represents amounts expensed by the Company in providing utility service in advance of receiving related goods or services."[82] Mr. Hill uses a slightly different explanation for the prepaid OPEB asset, describing it as "[s]imilar to the prepaid pension asset, a prepaid OPEB asset can be defined as cumulative OPEB cash contributions less OPEB cost."[83]

Q: DO YOU AGREE WITH MR. HILL'S DESCRIPTIONS OF THE PREPAID PENSION AND OPEB ASSETS?

A: I agree that Mr. Hill has described the assets the Company included in rate base, but I disagree that these descriptions justify the inclusion of those prepayments in rate base. To include a prepayment asset in rate base, it must be shown that the prepayments were not only *necessary* for the provision of service and *reasonable* in amount, but also that costs advanced by shareholders have not yet been collected from ratepayers through the rate setting process. While Mr. Hill described the pension asset as representing advanced funding, he described the OPEB asset as the difference between cash contributions and cost. That difference is significant and should be explored further to determine if the OPEB prepayment is the result of cost not previously recovered through the rate setting process.

<u>OPEB Analysis</u>

[82] See the Direct Testimony of Aaron L. Hill, p. 27, lines 18-19.
[83] Hill, p. 30, lines 9-10.

Q: IS THERE EVIDENCE THAT THE OPEB PREPAYMENT BALANCE DOES NOT REPRESENT COSTS ADVANCED BY SHAREHOLDERS IN EXCESS OF BENEFITS THE SHAREHOLDERS RECEIVED?

A: Yes. The response to OUCC Data Request 25-7, Attachment 1 includes a note explaining the origination of the prepaid balance in 2014. The note states, "[p]repaid account was established in 2014 when the plan benefits were changed as of 1/1/2014 to reduce benefits."[84] What the Company is saying in this note is that prior to 2014 it provided more generous benefits to employees, and the OPEB costs were higher in those years to the extent that the OPEB contributions did not exceed OPEB costs. This was addressed in AEP's 2012 SEC 10-K report, which states:

> In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical costs will be capped reducing our future exposure to medical cost inflation. <u>Effective for employees hired after December 2013, we will not provide retiree medical coverage. This change will reduce costs of the plan beginning in 2013 as shown by the estimated credits for Postretirement Plans in the previous paragraph</u>.[85]

Q: HOW HAS THE COMPANY BENEFITED FROM THIS CHANGE?

A: Future anticipated increases in employee medical costs result in a higher estimated future benefit liability which, in turn, causes an increase to the current OPEB expense each year. The prior uncapped future increases in medical costs had previously been included in OPEB expenses and recovered from ratepayers. When AEP made the decision to cap the future benefits, I&M recorded a reduction in the OPEB prior service credit of $78.85

[84] See Attachment MG-14, OUCC DR 25-7, Attachment 1.
[85] See AEP 2012 10-K Report, pdf page 559, American Electric Power 2012 Annual Reports, p. 39, final paragraph (emphasis added).

million for 2012.[86] Those prior service cost savings immediately benefited shareholders in the form of an increase in equity. With a stroke of a pen, AEP converted a liability to shareholder equity without spending a dollar to do it.

Q: HOW DID RATEPAYERS BENEFIT FROM CAPPING OF FUTURE RETIREE MEDICAL COSTS?

A: Ratepayers received a reduction in annual OPEB expense. In fact, OPEB expense has been negative since the change.

Q: WHAT IS THE PROBLEM WITH THIS RESULT?

A: The problem is that the Company has tried to convert the negative OPEB expense into a high-interest loan to ratepayers by including the accumulated balance of these expenses in rate base as a prepayment.

Q: DOES I&M'S CALCULATION OF THE OPEB PREPAYMENT REFLECT THE FACT THAT THE COMPANY HAS NOT MADE ANY CONTRIBUTIONS TO THE PLAN SINCE THE RETIREMENT BENEFITS WERE REDUCED?

A: Yes. The response to OUCC Data Request 25-7 shows the prepaid OPEB balance consists entirely of negative expense levels each year. OUCC DR 25-7, Attachment 1 contains an updated calculation of the OPEB prepayment as follows:

[86] See AEP 2012 10-K Report, pdf page 801.

Figure MG-8

Indiana Michigan Power Company
FAS 106 Prepaid OPEB History
Amounts Presented on an I&M Total Company Basis

Year	Beginning Balance	Establishment of Prepaid	Transfers	Expense (Credit) (Net Periodic Postretirement Benefit Cost)	December 31, Balance	Notes
2014	-	2,286,114	-	(9,099,426)	11,385,540	Prepaid account was established in 2014 when the plan benefits were changed as of 1/1/2014 to reduce benefits.
2015	11,385,540	-	(670,988)	(11,512,656)	22,227,208	
2016	22,227,208	-	-	(9,183,550)	31,410,759	
2017	31,410,759	-	-	(7,909,433)	39,320,191	
2018	39,320,191	-	14,713	(12,433,762)	51,768,666	
2019	51,768,666	-	11,469	(9,980,399)	61,760,535	
2020	61,760,535	-	(33,361)	(13,159,718)	74,886,893	
2021	74,886,893	-	4,373	(14,631,621)	89,522,887	The Company's updated OPEB expense (credit) (Net Periodic Postretirement Benefit Cost) projection has been annualized based on latest forecast from Willis Towers Watson.
2022 Test Year	89,522,887	-	-	(10,801,000)	100,323,887	The Company's updated OPEB expense (credit) (Net Periodic Postretirement Benefit Cost) projection for 2022 is now approximately $(14.4) million based upon the latest forecast from Willis Towers Watson.

The figure above show that there were no contributions from shareholders, only negative expense levels from ratepayers. Therefore, it cannot be said that the Company is not earning a return on capital contributed to OPEBs, because it has not contributed any capital. As a result, it is not entitled to earn a return on money it has not contributed.

Q: WHAT IS YOUR RECOMMENDATION REGARDING THE PREPAID OPEB ASSET THAT I&M INCLUDED IN RATE BASE?

A: I recommend that the Commission exclude the prepaid OPEB asset from rate base because it clearly does not represent contributions by the utility in excess of amounts collected from ratepayers. It is a balance made up entirely of negative expense levels over the past 7-year period. In other words, the Company is effectively seeking to charge ratepayers interest on the negative OPEB expense levels.

Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT TO REMOVE THE RATEPAYER FUNDED OPEB PREPAYMENT FROM RATE BASE?

A: The adjustment to remove the amount requested by I&M for prepaid OPEB costs reduces the total Company requested rate base by $96,252,892, or $69,324,472 for the Indiana jurisdiction. This adjustment is found on Schedule MG-16.

Prepaid Pension Analysis

Q: WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE COMPANY'S PREPAID PENSION BALANCE?

A: I&M's prepaid pension balance includes a starting balance of $84,582,060, which is an unexplained and unsupported amount from 2005 in the Company's prepaid pension calculations. For years after 2005, the Company is able to show, in OUCC DR 25-6, Attachment 1,[87] a year-by-year history of changes in the account balance, showing both increases in the balance from adding in contributions and decreases in the balance from netting out annual costs. Prior to 2005, however, the Company cannot account for what they claim is the existing starting balance. Without any support for this balance, it should not be included in rates. For this reason, I am proposing to adjust I&M's prepaid pension balance to remove this unsupported amount.

Q: WHAT DOES THE PREPAID PENSION BALANCE REPRESENT?

[87] See, Attachment MG-15, OUCC DR 25-6, Attachment 1.

A: The prepaid pension balance is intended to represent the Company's contributions to the plan in excess of the amounts collected from ratepayers to fund these contributions. I&M calculates the prepaid pension balance as the accumulated difference between (1) the Statement of Financial Accounting Standards No. 87 ("SFAS 87") calculated net periodic pension costs each year – the amount intended to represent the amount included in rates – and (2) the actual contributions made by the Company to the pension fund. When there is a debit balance, the Company asserts that it has contributed more to the fund than its SFAS 87 calculated cost levels. Or, in theory, the Company has contributed more to the pension fund than it has collected in rates.

Q: DO YOU AGREE WITH THIS COMPARISON?

A: No. The more accurate comparison would be to compare the actual amounts embedded in rates in each rate case with the amounts contributed to the fund by the Company. This is the appropriate comparison because it would accurately reflect the difference between the amounts collected from ratepayers and the amounts I&M actually contributed to the fund. This would show if I&M actually made a net investment in the fund in excess of the amounts reimbursed by ratepayers.

Q: CAN YOU PROVIDE A SIMPLE EXAMPLE OF THE TWO COMPARISONS?

A: Yes. In the example below, the utility has a rate case in Year 1 and includes $10M in rates, because that is its net period pension costs in that year. The utility also contributes $50M to the pension fund. Over the next several years, net periodic pension cost decreases, but the amount embedded in rates stays the same, as it would between rate cases. In Year 5, the Company has another rate case and claims a $30M prepaid pension asset, based on the difference between cash contributions and net periodic pension costs. However, there is no real outlay of cash from the utility in excess of the amounts collected from ratepayers. In this example, the prepaid pension asset would be zero, because the amount collected in rates equals the amount contributed to the pension fund.

Table 1: Prepaid Pension Illustration

A	B	C	D
Year	Contributions	Net Periodic Costs	Amount in Rates
1	$50,000,000	$10,000,000	$10,000,000
2		$5,000,000	$10,000,000
3		$2,000,000	$10,000,000
4		$2,000,000	$10,000,000
5		$1,000,000	$10,000,000
Totals	$50,000,000	$20,000,000	$50,000,000
PSO Prepaid Pensions Asset (B - C)		$30,000,000	
Actual Pension Asset (B - D)			$0

Q: HOW DOES THIS EXAMPLE RELATE TO THIS CASE?

A: In this case, I&M has requested a prepaid pension asset based on the accumulated difference between columns B and C. However, the appropriate comparison for ratemaking purposes would be the difference between columns B and D. In other words, the comparison is between what the utility has contributed to the fund and what it has collected from ratepayers.

Q: HAS THE PENSION EXPENSE ALWAYS BEEN BASED ON THE FAS 87 NET PERIODIC PENSION COSTS?

A: No. Prior to the promulgation of FAS 87 pension costs and the amounts recovered in rates were often based on cash contributions to pension funds and the pension funds were often over funded as a result. Any prepayment from that period would have been funded by ratepayers, not shareholders. The fact that I&M will not bother to support its initial balance is very concerning. It should also be noted that the 1985 initial balance of $84,582,060[88] is greater than the test year-end balance of $80,675,062.[89] In other words, the entire prepaid pension balance is made up of unsupported amounts.

Q: DOES THE EMBEDDED EXPENSE INCLUDE THE FULL PENSION COSTS BORNE BY RATEPAYERS?

A: No. I&M has been collecting a return on the prepaid pension asset in rates for several years and admits that it has omitted that from ratepayers' contribution to pension costs.[90] The table below is based on OUCC DR 25-4, Attachment 1, and shows the amount of pension-related costs borne by ratepayers.

Table 2: I&M Pension Related Costs Recovered from Ratepayers

Cause No.	Effective Date	Authorized Rate of Return	Pension Prepayment Ind. Juris.	Annual Return	Months Embedded in Rates	Return Recovered
43306	3/23/2009	7.62%	$70,999,238	$5,410,142	47	$21,189,723
44075	2/28/2013	6.97%	$61,691,738	$4,299,914	65	$23,291,202
44967	7/1/2018	5.51%	$70,598,516	$3,889,978	20	$6,483,297
45235	3/11/2020	5.61%	$59,133,216	$3,317,373	21	$5,805,403
Total Prepaid Pension Return Recovered from Ratepayers through 12/31/21						**$56,769,625**

[88] See Attachment MG-15, OUCC DR 25-06, Attachment 1.
[89] See Exhibit A-2, page 2, account Prepaid Pension Benefits (165 0010).
[90] See Attachment MG-16, OUCC DR 25-05.

This ratepayer-borne pension cost is only slightly less than the $58,104,811 jurisdictional pension prepayment claimed by the Company. The returns included in the table do not include income taxes as requested in the discovery request, so the actual ratepayer pension cost *paid* in rates since 2009 is much higher.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Company remove its prepaid pension asset from rate base and provide an analysis that compares *actual* cash contributions made by the Company with the *actual* amounts collected in rates. If the Company can show that it has actually contributed more to the pension fund than it has collected from ratepayers, it should submit that amount for inclusion in rate base in its next rate case. The amount currently requested by I&M is not correctly calculated or adequately supported.

Q: WHAT ADJUSTMENT ARE YOU PROPOSING?

A: I am proposing to remove the requested prepaid pension balance until I&M can provide an analysis of its actual prepaid pension balance, if any, which compares I&M's contributions to the amounts embedded in rates including a full history since the adoption of FAS 87.

Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT YOU ARE PROPOSING?

A: The adjustment to remove the requested prepaid pension costs from rate base reduces the Indiana jurisdictional rate base by $58,104,811. When combined with the removal or the requested prepaid OPEB cost of $69,324,472 discuss above, the total adjustment for prepaid pension and OPEB costs reduces rate base by $127,429,283. These adjustments are found on Schedule MG-16.

II. H. FACTORING EXPENSE

Q: PLEASE DESCRIBE YOUR ADJUSTMENT TO FACTORING EXPENSE.

A: I&M and another affiliate of AEP, AEP Credit, Inc., maintain a contractual arrangement whereby AEP Credit purchases, without recourse, certain accounts receivable arising from the sale and delivery of electricity in the State of Indiana. The process of one company selling its accounts receivable, usually at a discount, to a third-party purchaser is called factoring. This gives rise to factoring expense. In its 2022 forecasted test year, the Company included $11.9 million in O&M for factoring expense, of which $9.6 million is assigned to the Indiana jurisdiction based upon the receivables which the Company sells.[91]

Q: HAVE YOU COMPARED THE COMPANY'S FORECASTED TEST YEAR FACTORING EXPENSE WITH ITS HISTORICAL DATA?

A: Yes. The Company's factoring expenses for the past two years are set forth in the workpapers sponsored by I&M witness Dona Seger-Lawson.[92] Ms. Seger-Lawson increased the test year factoring expense based on a two year average in an effort to increase the expense for the effects of COVID-19, arguing that the increase is necessary even though the Company is requesting the incremental increase in bad debt expense

[91] See WP-OM-1.
[92] *Id*.

related to COVID as a separate expense.[93] To ascertain the reasonableness of the Company's forecasted test year factoring expense level, I compared it to the Company's three-year factoring expense levels for 2018 through 2020, consistent with I&M's most recent rate case.

Based upon the Company's actual experience, its 3-year average Total Company factoring expense is $10.7 million. Because the forecasted 2022 factoring expense level is not known, I recommend an adjustment to reduce the Company's expense to reflect the most recent 3-year average factoring expense. The two-year average advocated by Ms. Seger-Lawson fails to recognize that the increased bad debt expense for 2020 was as dramatic as it was because of the economic shutdown. While the COVID pandemic continues to take a toll, another full shutdown of the economy is unlikely. The three-year average used in the past to normalize bad debt expense will still include an increase in bad debt expense, just less than Ms. Seger-Lawson is advocating. This adjustment results in a decrease of $863,440 to the Indiana jurisdictional O&M expense and is set forth on Schedule MG-17.

III. DEPRECIATION EXPENSE

Q: DOES OUCC PROPOSE DEPRECIATION EXPENSE ADJUSTMENTS?

A: Yes. Mr. David Garrett proposes changes to the Company's depreciation study on behalf of OUCC. His recommendations result in new proposed depreciation rates for several of the Company's accounts, which are set forth in Schedule MG-18.

[93] See the Direct Testimony of Dona Seger-Lawson, p. 17, lines 1-36.

IV. COST OF CAPITAL

Q: DOES OUCC PROPOSE COST OF CAPITAL RECOMMENDATIONS?

A: Mr. David Garrett provides testimony on behalf of OUCC regarding cost of capital issues. The impacts of his cost of capital recommendations on the revenue requirement are set forth in Schedule MG-20.

V. TESTIMONY OF OTHER OUCC WITNESSES

Q: DO YOUR SCHEDULES INCLUDE ADJUSTMENTS SPONSORED BY OTHER OUCC WITNESSES?

A: Yes. Schedules MG-9 and MG-10 include adjustments from OUCC witnesses, as shown below:

Figure MG-9

Issue	OUCC Witness	Proposed Adjustment
Rate Base		Indiana Retail
EV Fast Chargers	Haselden	$(3,783,088)
Flex Pay Program	Loveman	$(568,770)
AMI Program	Alvarez	$(20,200,000)
Combined Projects	Alvarez	$(1,614,688)
Combined Projects	Alvarez	$(28,078,466)
Deferred Bad Debt Expense	Blakley	$(2,023,141)
Rockport Unit 2	Blakley	$(72,779,725)
Cybersecurity	Lantrip	$(11,976,146)
O&M Adjustments		
Cybersecurity	Lantrip	$(3,855,395)
Nuclear Decommissioning Fund	Eckert	$(2,000,000)
Rate Case Expense	Eckert	$(403,493)
Flex Pay Expense	Loveman	$(11,347)
Deferred Bad Debt Expense	Blakley	$(239,773)
Purchased Power Capacity	Lantrip	$(1,068,923)

VI. OUCC REVENUE REQUIREMENT SUMMARY

INDIANA MICHIGAN POWER COMPANY
Adjustment Summary
For the Test Year Ending December 31, 2022

Line	Description	Ref.	Witness	Rate Base	Pre-Tax ROR	Rate Increase
1	Requested Amounts[1]			$ 5,235,969,265		$ 110,713,174
2	Rate Base Adjustments					
3	Capitalized STI	Sch. MG-12	M. Garrett	$ (3,350,590)	7.606781%	$ (254,872)
4	Capitalized LTI	Sch. MG-13	M. Garrett	(1,875,926)	7.606781%	(142,698)
5	Remove Prepaid Pension Expense	Sch MG-16	M. Garrett	(127,429,283)	7.606781%	(9,693,266)
6	EV Fast Charging	Sch MG-9	Haselden	(3,783,088)	7.606781%	(287,771)
7	Flex Pay Program		Loveman	(568,770)	7.606781%	(43,265)
8	AMI Program		Alvarez	(20,200,000)	7.606781%	(1,536,570)
9	Combined Projects		Alvarez	(1,614,688)	7.606781%	(122,826)
10	Combined Projects		Alvarez	(28,078,466)	7.606781%	(2,135,867)
11	Deferred Bad Debt Expense		Blakley	(2,023,141)	7.606781%	(153,896)
12	Rockport Unit 2		Blakley	(72,779,725)	7.606781%	(5,536,194)
13	Cybersecurity		Lantrip	(11,976,146)	7.606781%	(910,999)
14	Total Rate Base Adjustments			$ (273,679,823)		$ (20,818,225)
15	Cost of Capital Adjustments					
16	Capital Structure	Sch. MG-21	M. Garrett	$ 4,962,289,442	-0.138469%	$ (6,871,210)
17	Return on Equity	9.10%	D. Garrett	$ 4,962,289,442	-0.510869%	(25,350,777)
18	Total Cost of Capital Adjustments					$ (32,221,987)
19	Operating Income Adjustments					
20	Vacant Positions	Sch. MG-11	M. Garrett			$ (8,088,829)
21	Short-Term Incentive Plans	Sch. MG-12	M. Garrett			$ (8,646,111)
22	Long-Term Incentive Plans	Sch. MG-13	M. Garrett			(5,640,187)
23	SERP	Sch. MG-14	M. Garrett			(151,543)
24	Pensions and Benefits	Sch. MG-15	M. Garrett			(1,990,473)
25	Factoring	Sch. MG-17	M. Garrett			(863,440)
26	Cybersecurity	Sch. MG-10	Lantrip			(3,855,395)
27	Nuclear Decommissioning Fund	Sch. MG-10	Eckert			(2,000,000)
28	Rate Case Expense	Sch. MG-10	Eckert			(403,493)
29	Flex Pay Program	Sch. MG-10	Loveman			(11,347)
30	Deferred Bad Debt Expense	Sch. MG-10	Blakley			(239,773)
31	Purchased Power Capacity	Sch. MG-10	Lantrip			(1,068,923)
32	Depreciation Adjustment	Sch. MG-18	D. Garrett			(29,905,443)
33	Rate Case Expense	Sch. MG-8	M. Garrett			(299,914)
34	Additional Uncollectible Accounts	Calc.	M. Garrett			(178,701)
35	Additional Utility Tax / Assessment	Calc.	M. Garrett			(948,851)
36	Other - Rounding Differences[2]					283,974
37	Total Adjustments to Operating Income					$ (64,008,449)
38	Total Adjustments					$ (117,048,660)
39	**Net Increase in Rates**					**$ (6,335,487)**

VII. CONCLUSION

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes, it does.

MARK E. GARRETT

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EDUCATION:
Juris Doctor Degree, With Honors, Oklahoma City University Law School, 1997
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:
University of Texas at Arlington; University of Texas at Pan American;
Stephen F. Austin State University
Bachelor of Arts Degree, University of Oklahoma, 1978

CREDENTIALS:
Member Oklahoma Bar Association, 1997, License No. 017629
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R
Certified Public Accountant in Texas, 1986, Certificate No. 48514

WORK HISTORY:

GARRETT GROUP CONSULTING, INC. – Regulatory Consulting Practice (1996 - Present) Participates as a consultant and expert witness in gas and electric regulatory proceedings and other matters before regulatory agencies in rate case proceedings to determine just and reasonable rates. Reviews management decisions of regulated utilities regarding the reasonableness of prices paid for electric plant, gas plant, purchased power, renewable energy projects, natural gas supplies and transportation, and coal supplies and transportation. Participates in legislative advisory role regarding regulated utilities. Participates as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1994) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller (1987 - 1990) Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPAs - Auditor (1986 - 1987) Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Cascade Natural Gas, 2021 (Washington)** – Participating as an expert witness on behalf of Public Counsel in Cascade's limited issue rate case application, sponsoring Public Counsel's revenue requirement schedules and testimony to address various revenue requirement and tax issues.

2. **Southwestern Electric Power Company, 2021 (Texas), (PUC Docket No. 52397)** – Participating as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's application to recover Uri storm costs.

3. **Southwestern Public Service Co., 2021 (Texas) (Docket No. 52210) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") before the Texas Public Utility Commission in SWEPCO's application to recover Uri storm costs.

4. **CenterPoint Energy Resources Corp., 2021 (Texas) (Docket No. OS—00007061)** – Participating as an expert witness for the City of Houston before the Texas Rail Road Commission in a consolidated application from the large natural gas distribution utilities in Texas to securitize and recover URI storm costs from February 2021.

5. **Indiana Michigan Power, 2021 (Indiana), (Docket No. 45576) –** Participating as an expert witness on behalf of the Office of Utility Consumer Counselor in I&M's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

6. **Chugach Electric Association, 2021 (Alaska), (Docket No. U-21-059)** – Participating as an expert witness on behalf of Providence Health and Services before the Alaska Regulatory Commission. Sponsoring testimony to address Chugach's application to address a shortfall in revenues after its acquisition of Municipal Light and Power.

7. **Southwestern Public Service Co., 2021 (Texas) (Docket No. 51802) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues.

8. **El Paso Electric Company, 2021 (Texas), (Docket No. 52195)** – Participating as an expert witness on behalf of the City of El Paso in the El Paso Electric Company general rate case to provide recommendations to the Texas Public Utility Commission regarding rate base and operating expense issues.

9. **NV Energy, 2021 (Nevada), (Docket No. 21-06001)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group ("SNGG") before the Nevada PUC. Sponsoring written and oral testimony in the Nevada Power and Sierra Pacific Joint Integrated Resource Plan ("IRP") to provide analysis of the proposed generation additions and cost allocations.

10. **Summit Utilities Arkansas (Arkansas), (Docket No. 21-060-U)** – Participating as an expert witness on behalf of Arkansas Gas Consumers and the Hospitals and Higher Education Group before the Arkansas Public Service Commission in Summit's proposed acquisition of CenterPoint Energy's Arkansas assets. Sponsoring testimony regarding the acquisition premium, ratepayer benefits and affiliate transactions.

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11. **Doyon Utilities, 2021 Alaska (Regulatory Commission of Alaska)** – Participating as an expert witness on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

12. **NV Energy, 2021 (Nevada), (Docket No. 21-03040)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group ("SNGG") before the Nevada PUC to provide written and oral testimony in the Nevada Power and Sierra Pacific Joint Natural Disaster Protection Plan ("NDPP").

13. **Public Service Company of Oklahoma, 2021 (Oklahoma) (Cause No. PUD 202100022)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

14. **Oklahoma Gas and Electric Company, 2021 (Oklahoma), (Cause No. PUD 202100072) –** Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC")1 before the Oklahoma Corporation Commission in OG&E's application for securitization of its winter storm costs.

15. **Southwestern Electric Power Company, 2021 (Arkansas), (Docket No. 19-008-U)** – Participating as an expert witness on behalf of Western Arkansas Large Energy Consumers ("WALEC")2 before the Arkansas Public Service Commission in SWEPCO's Formula Rate Plan review and extraordinary winter storm cost recovery plan.

16. **Atmos MidTex (Texas), 2021 (Texas), (Dallas Annual Rate Review) –** Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring recommendations on various revenue requirement issues.

17. **PNM Resources / Avangrid Merger, 2021 (New Mexico), (Case No. 20-00222-UT)** – Participating as an expert witness for the Albuquerque Bernalillo County Water Utility Authority ("ABCWUA") before the New Mexico Public Regulation Commission to address various merger-related issues.

18. **Oklahoma Gas & Electric Co., 2020 (Arkansas) (Docket No. 18-046-FR)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC")[3] before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on cost of service issues.

19. **Public Service Company of Oklahoma, 2020 (Oklahoma) (Cause No. PUD 202000097)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application for approval of facilities proposed for Fort Sill to address cost recovery and rate design issues.

20. **El Paso Electric Company, 2020 (Texas), (Docket No. 51348)** – Participating as an expert witness on behalf of the City of El Paso in the El Paso Electric Company annual Distribution Cost Recovery

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[1] OIEC is an association of industrial manufacturing facilities in Oklahoma.
[2] WALEC is an association of industrial manufacturing facilities in Arkansas.
[3] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

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Factor (“DCRF”) application to provide recommendations to the Texas Public Utility Commission regarding the Company’s requested DCRF increase.

21. **NV Energy, 2020 (Nevada), (Docket No. 20-07023)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group (“SNGG”) before the Nevada PUC. Sponsoring written and oral testimony in the Nevada Power and Sierra Pacific Joint Integrated Resource Plan (“IRP”) to provide analysis of the proposed transmission additions and cost allocations.

22. **Southwestern Electric Power Company, 2020 (Texas), (PUC Docket No. 51415)** – Participating as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case application to provide testimony on various revenue requirement issues.

23. **Dominion Energy South Carolina, 2020 (South Carolina), (Docket No. 2020-125-E) –** Participating as an expert witness on behalf of DOD/FEA in DESC’s rate case application, sponsoring testimony to address various revenue requirement, rate design and tax issues.

24. **Cascade Natural Gas, 2020 (Washington), (NG-UG-200568)** – Participating as an expert witness on behalf of Public Counsel in Cascade’s rate case application, sponsoring testimony to address various revenue requirement and tax issues.

25. **Nevada Power Company, 2020 (Nevada) (Docket No. 20-06003)** – Participating as an expert witness on behalf of Bureau of Consumer Protection (“BCP”) before the Nevada Public Utility Commission to address various revenue requirement issues in the case.

26. **El Paso Electric Company, 2020 (New Mexico), (Docket RC-20-00104-UT)** – Participating as an expert witness on behalf of the City of Las Cruces and Dona Ana county in EPE’s rate case application, sponsoring testimony to address various revenue requirement and tax issues.

27. **Oklahoma Gas and Electric Company, 2020 (Oklahoma), (Cause No. PUD 202000021) –** Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in OG&E’s Grid Enhancement Plan application. Sponsoring testimony to address the utility’s proposed cost recovery mechanism and cost of service allocations.

28. **Philadelphia Gas Works, 2020 (Pennsylvania), (Docket No. R-2020-3017206)** – Participating expert witness on behalf of Office of Consumer Advocate (“OCA”) before the Pennsylvania Public Utility Commission to address various revenue requirement issues in PGW’s rate case.

29. **Atmos MidTex (Texas), 2020 (Texas), (Dallas Annual Rate Review) –** Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos’s Dallas Annual Rate Review (“DARR”) proceeding. Sponsoring recommendations on various revenue requirement issues.

30. **Southwest Gas Corporation, 2020 (Nevada) (Docket No. 20-02023)** – Participated as an expert witness on behalf of Bureau of Consumer Protection (“BCP”) before the Nevada Public Utility Commission to address various revenue requirement issues.

31. **El Paso Electric Company, 2019 (Texas), (Docket No. 49849)** – Participating as an expert witness on behalf of the City of El Paso in the merger of El Paso Electric Company with Sun Jupiter

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Holdings LLC and IIF US Holdings 2 LLP to provide recommendations to the Texas Public Utility Commission regarding the treatment of tax issues in the proposed merger agreement.

32. **Nevada Senate Bill 300 Rulemaking, 2019 (Nevada), (Docket No. 19-069008)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC to assist with the development of alternative ratemaking regulations under SB 300.

33. **Entergy Arkansas, 2019 (Arkansas), (Docket No**. 19-020-TF) – Participating as an expert witness on behalf of the Arkansas industrial consumer group to review EAI's application to allocate its perceived under-recovery of off-system sales margins to Arkansas customers.

34. **Public Service Company of Oklahoma, 2019 (Oklahoma) (Cause No. PUD 201900201)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application for approval for the cost recovery of selected wind facilities.

35. **Oklahoma Gas & Electric Co., 2019 (Arkansas) (Docket No. 15-034-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Act 310 Environmental Compliance Plan ("ECP") Rider case to provide testimony on whether OG&E can apply for an ECP rider now that it has elected to utilize an annual Formula Rate Plan with a 4% annual cap.

36. **Oklahoma Gas & Electric Co., 2019 (Arkansas) (Docket No. 18-046-FR)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.

37. **Southwestern Public Service Co., ("SPS") 2019 (Texas), (Docket No. 49831) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

38. **Southwestern Electric Power Company, 2019 (Arkansas), (Docket No. 19-008-U)** – Participated as an expert witness on behalf of Western Arkansas Large Energy Consumers ("WALEC") before the Arkansas Public Service Commission in SWEPCO's rate case to address various revenue requirement and rate design issues.

39. **Anchorage Municipal Light and Power and Chugach Electric Association, 2019 (Alaska), (Docket No. U-19-020) –** Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on pending acquisition of ML&P by Chugach to address the proposed acquisition premium and other issues associated with the public interest.

40. **Sierra Pacific Power Company, 2019 (Nevada), (Docket No. 19-06002)** – Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

41. **Air Liquide Hydrogen Energy U.S., 2019 (Nevada), (704B Exit Application, Docket No. 19-02002)** – Participated as an expert witness on behalf of Air Liquide before the Nevada PUC. Sponsoring written and oral testimony in Air Liquide's application to purchase energy and capacity from a provider other than NV Energy.

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42. **Empire District Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800133)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's general rate case to address various revenue requirement, rate design and tax issues.

43. **Indiana Michigan Power, 2019 (Indiana), (Docket No. 45235) –** Participating as an expert witness on behalf of the Office of Utility Consumer Counselor in I&M's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

44. **Puget Sound Energy, 2019 (Washington), (Docket No. 190529-30)** – Participating as an expert witness on behalf of Public Counsel in PSE's rate case application, sponsoring testimony to address various revenue requirement and tax issues.

45. **Anchorage Municipal Light and Power, 2019 (Alaska), (Docket No. U-18-102) –** Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P's acquired interest in the Beluga River Unit gas field with ratepayer funds.

46. **Oklahoma Gas and Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800140) –** Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

47. **Cascade Natural Gas, 2019 (Washington) (Docket No. 190210)** – Participated as an expert witness on behalf of Public Counsel in Cascade's rate case application. Sponsoring testimony to address various revenue requirement and tax issues.

48. **CenterPoint Energy Houston Electric, 2019 (Texas) (Docket No. 49421)** – Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy's rate case application to provide testimony on various revenue requirement issues.

49. **Oklahoma Gas & Electric Co., 2018 (Arkansas) (Docket No. 18-046-FR** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.

50. **Southwest Gas Corporation, 2018 (Nevada) (Docket No. 18-05031)** – Participated as an expert witness on behalf of Bureau of Consumer Protection ("BCP") before the Nevada Public Utility Commission to address various revenue requirement issues.

51. **Puget Sound Energy, 2018 (Washington) (Docket No. UE 18089) -** Participated as an expert witness on behalf of Public Counsel in PSE's Emergency Rate Relief proceeding. Sponsoring testimony to address the application itself and various revenue requirement and TCJA issues.

52. **Public Service Company of Oklahoma, 2018 (Oklahoma) (Cause No. PUD 201800097) –** Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

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53. **Entergy Texas Inc., 2018 (Texas) (PUC Docket No. 48371) –** Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

54. **Atmos Energy Corp., Mid-Tex Division, 2018 (Texas) (Docket No. GUD No. 10779)** – Participated as an expert witness on behalf of the Atmos Texas Municipalities to review the utility's requested revenue requirement including TCJA adjustments.

55. **CenterPoint Energy Houston Electric, LLC, 2018 (Texas) (Docket No. 48226)** – Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy's application for approval to amend its distribution cost recovery factor (DCRF) to address the utility's treatment of the Tax Cuts and Jobs Act of 2017 ("TCJA").

56. **NV Energy, 2018 (Nevada) (Docket No. 17-10001)** – Participated as an expert witness on behalf of the Energy Choice Initiative ("ECI") before the Governor's Committee on Energy Choice, in an investigatory docket of an Issue of Public Importance Regarding the Pending Energy Choice Initiative and the Possible Restructuring of Nevada's Energy Industry.

57. **Southwestern Electric Power Company, 2018 (Texas) (PUC Docket No. 48233) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's application to implement bae rate reductions as result of the Tax Cuts and Jobs Act of 2017 ("TCJA").

58. **Oncor Electric Delivery Company (Texas), 2018 (PUC Docket No. 48325)** – Participated as an expert witness before the Texas Public Utility Commission in Oncor's application for authority to decrease rates based on the Tax Cuts and Jobs Act of 2017 ("TCJA").

59. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2018 (Cause No. PUD 201800019)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application regarding ADIT under the Tax Cuts and Jobs Act of 2017 ("TCJA").

60. **Oklahoma Natural Gas Company, 2018 (Cause No. PUD 201800028) –** Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's Performance Based Rate Change Tariff, to address issues involving the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA").

61. **Oklahoma Gas & Electric Co. (Arkansas), 2018 (Docket No. 18-006-U** – Participated as an expert on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in the matter of an Investigation of the Effect on Revenue Requirements Resulting from Changes to Corporate Income Tax Rates under the Tax Cuts and Jobs Act of 2017 ("TCJA").

62. **Texas Gas Service, 2018 –** Participated as a consulting expert on behalf of the City of El Paso regarding implementation of rate changes related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

63. **Sierra Pacific Power Company (Nevada), 2018 (Docket No. 18-02011 and 18-02015)** –

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Participated as an expert witness on behalf of the Northern Nevada Utility Customers[4] before the Nevada PUC in SPPC's application related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

64. **Nevada Power Company (Nevada), 2018 (Docket No. 18-02010 and 18-02014)** – Participated as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC in NPC's application related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

65. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2017 (Cause No. PUD 201700572)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's application to examine the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA").

66. **Empire District Electric Company ("EPE") (Oklahoma), 2018 (Cause No. PUD 201700471)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's application to add 800MW of wind. Sponsoring testimony to address the various ratemaking and tax issues.

67. **Oklahoma Gas and Electric Company ("OG&E"), (Oklahoma), 2018 (Cause No. PUD 201700496) –** Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

68. **Public Service Company of Oklahoma ("PSO") (Oklahoma), 2017 (Cause No. PUD 201700276)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's Wind Catcher case to provide testimony on various ratemaking and tax issues.

69. **Southwestern Public Service Co. ("SPS") (Texas), 2017 (PUCT Docket No. 47527) –** Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

70. **Southwestern Electric Power Company, ("SWEPCO") (Texas), 2017 (PUC Docket No. 47461)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's Wind Catcher case proceeding to provide testimony on various ratemaking and tax issues.

71. **Atmos MidTex (Texas), 2017 (Docket No. 10640) –** Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos's Dallas Annual Rate Review ("DARR") proceeding. Sponsoring testimony on various revenue requirement issues.

72. **Avista Utilities (Washington), 2017 (Docket Nos. UE-170485/UG-170486)** – Participated as an expert witness on behalf of Public Counsel in Avista's general rate case proceeding. Sponsoring testimony to address various revenue requirement issues and Avista's requested attrition adjustments.

73. **Nevada Power Company (Nevada), 2017 (Docket No. 17-06003)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC in NPC's general rate case proceeding. Sponsoring testimony on various revenue requirement, depreciation, and rate

[4] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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design issues.

74. **Anchorage Municipal Light and Power (Alaska), 2017 (Docket No. U-17-008) –** Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony in ML&P's General Rate Case on various revenue requirement and rate design issues.

75. **Public Service Company of Oklahoma (Oklahoma), 2017 (Cause No. PUD 201700151)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various revenue requirement and rate design issues.

76. **Oncor Electric Delivery Company (Texas), 2017 (PUC Docket No. 46957)** – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Public Utility Commission in Oncor's General Rate Case proceeding to provide testimony on various revenue requirement issues.

77. **EverSource (Massachusetts), 2017 (DPU Docket No. 17-05) –** Participated as an expert witness before the Massachusetts Department of Public Utilities EverSource's General Rate Case application on behalf of Energy Freedom Coalition of America to provide testimony to address various revenue requirement issues.

78. **El Paso Electric Company (Texas), 2017 (PUC Docket No. 46831)** – Participated as an expert witness on behalf of the City of El Paso before the Texas Public Utility Commission in El Paso's General Rate Case proceeding to provide testimony on various revenue requirement issues.

79. **Atmos Pipeline Texas (Texas), 2017 (Docket No. 10580)** – Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in APT's General Rate Case application, sponsoring testimony to address various revenue requirement proposals.

80. **Empire District Electric Company (Oklahoma), 2017 (Cause No. PUD 201600468) –** Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in Empire's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

81. **Caesars Enterprise Service, LLC (Nevada), 2016 (704B Exit Application)** – Participated as an expert witness on behalf of Caesars before the Nevada PUC. Sponsoring written and oral testimony in Caesar's application to purchase energy and capacity from a provider other than Nevada Power.

82. **Southwestern Electric Power Company (Texas), 2016 (PUC Docket No. 46449) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various revenue requirement issues.

83. **CenterPoint Texas, 2016 (Docket No. 10567) –** Participated as an expert witness on behalf of City of Houston before the Texas Railroad Commission in CenterPoint's general rate case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

84. **Entergy Texas, Inc., 2016 (Docket No. 46357) –** Participated as an expert witness on behalf Cities Served by Applicant before the Texas PUC in ETI's application to amend its Transmission Cost

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Recovery Factor.

85. **Anchorage Municipal Light and Power, 2016 (Docket No. U-16-060) –** Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P's acquired interest in the Beluga River Unit gas field with ratepayer funds.

86. **Arizona Public Service Company, 2016 (Docket No. E-01345A-16-0036)** – Participated as an expert witness before the Arizona Corporation Commission in APS's General Rate Case application on behalf of Energy Freedom Coalition of America to provide written and oral testimony to address various revenue requirement issues.

87. **Oklahoma Gas & Electric Co. (Arkansas), 2016 (Docket No. 16-052-U** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

88. **Sierra Pacific Power Company (Nevada), 2016 (Docket No. 16-06006) –** Participated as an expert witness on behalf of the Northern Nevada Utility Customers before the Nevada PUC in SPPC's general rate case proceeding. Sponsored testimony on various revenue requirement, depreciation, and rate design issues.

89. **Tucson Electric Power, 2016 (Docket No. E-01933A-15-0322)** – Participated as an expert witness before the Arizona Corporation Commission in TEP's General Rate Case application, on behalf of Energy Freedom Coalition of America providing written and oral testimony to address the utility's cost of service study and rate design proposals.

90. **Texas Gas Service, 2016 (Docket No. 10506)** – Participated as an expert witness on behalf of El Paso before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

91. **Texas Gas Service, 2016 (Docket No. 10488) –** Participated as an expert witness on behalf of South Jefferson County Service Area ("SJCSA") before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

92. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

93. **Oklahoma Gas & Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.

94. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097) –** Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.

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95. **Oklahoma Natural Gas Company, 2015 (Cause No. PUD 201500213)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's General Rate Case application. Sponsored testimony to address the utility's overall revenue requirement and rate design proposals.

96. **Oklahoma Gas & Electric Company, 2015 (Cause No. PUD 201500274)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.

97. **Nevada Power Company, 2015** (Docket No. 15-07004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG")[5] before the Nevada PUC. Sponsoring written and oral testimony in NPC's 2015 Integrated Resource Plan to provide analysis of the On Line transmission line allocation, the Siverhawk plant acquisition, and the Griffith contract termination.

98. **Oklahoma Gas & Electric Company, 2015 (Docket No. 15-034-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC") before the Arkansas Public Service Commission in OG&E's Act 310 application to implement a rider to recover environmental compliance costs.

99. **MGM Resorts, LLC, 2015** (Docket No. 15-05017) – Participated as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM's application to purchase energy and capacity from a provider other than Nevada Power.

100. **Entergy Arkansas, 2015 (Docket No. 15-015-U) –** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

101. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

102. **Nevada Power Company, 2014** (Docket No. 14-05003) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored written and oral testimony in NPC environmental compliance case, called the Emissions Reduction and Capacity Replacement case. The main focus of our testimony was our recommendation to eliminate the $438M Moapa solar project from the compliance plan.

103. **Nevada Power Company, 2014** (Docket No. 14-05004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsor written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

[5] The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.

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104. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") in OG&E's Environmental Compliance and Mustang Modernization Plan before the Oklahoma Corporation Commission to provide testimony addressing the economics and rate impacts of the plan.

105. **Sourcegas Arkansas, Inc., 2014 (Docket No. 13-079-U)** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG"), an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in SGA's general rate case to provide testimony on various revenue requirement issues.

106. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184) –** Participated as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.

107. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

108. **Entergy Texas Inc., 2013 (PUC Docket No. 41791) –** Participated as an expert witness on behalf of the Cities[6] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

109. **MidAmerican/NV Energy Merger, 2013 (Docket No. 13-07021) –** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored testimony to address various issues raised in the proposed acquisition of NV Energy by MidAmerican Energy Holdings Company, including capital structure and acquisition premium recovery issues.

110. **Entergy Arkansas, 2013 (Docket No. 13-028-U) –** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

111. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002) –** Participated as an expert witness on behalf of the Northern Nevada Utility Customers[7] before the Nevada PUC in SPPC's general rate case proceeding to provide testimony on various cost of service and revenue requirement issues. Sponsored written and oral testimony in the depreciation phase, the revenue requirement phase and the rate design phase of these proceedings.

112. **Gulf Power Company, 2013 (Docket No. 130140-EI) –** Participated as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power's general rate case proceeding to provide testimony on various revenue requirement issues.

113. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054) –** Participated as an

[6] The Cities include Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange.
[7] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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expert witness on behalf of the OIEC before the Oklahoma Corporation Commission ("OCC") to provide testimony in PSO's application seeking Commission approval of its settlement agreement with EPA.

114. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443) –** Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

115. **Doyon Utilities, 2012 Alaska Rate Case** (Docket No. TA7-717) – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

116. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University's general rate case with the Corix Group, which provides utility services to the University.

117. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079) –** Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility's request to earn additional compensation on a 510MW purchased power agreement with Exelon

118. **Centerpoint Energy Texas Gas, 2012 (Docket No.** GUD 10182) – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.

119. **Entergy Texas Inc., 2012 (PUC Docket No. 39896) –** Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

120. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG's Performance Based Rate ("PBR") application seeking Commission approval of a requested rate increase based upon formula results for 2011.

121. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.

122. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.

123. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

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124. **Nevada Power Company, 2011, (Docket No. 11-04010) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored written and oral testimony to address proposed changes to the Company's customer deposit rules.

125. **Nevada Power Company, 2011, (Docket No. 11-06006) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

126. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking rider recovery of third party SPP transmission costs and fees.

127. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

128. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E's application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.

129. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking to include retiree medical expense in the Company's pension tracker mechanism.

130. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO's application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.

131. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E) –** Participated as an expert witness on behalf of the Colorado Retail Council ("CRC") before the Colorado Public Utilities Commission providing written and live testimony to address PSCo's proposed Environmental Tariff.

132. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers ("NWIEC")[8] before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

133. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking rider recovery of third party SPP transmission costs and SPP administration fees.

134. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of

[8] NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

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Massachusetts ("AIM") to address the Company's proposed participation in the 438MW Cape Wind project in Nantucket Sound.

135. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

136. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

137. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147) –** Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

138. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participated as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E's 220MW self-build wind project.

139. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking pre-approval of deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.

140. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01)** – Participated as an expert witness on behalf of the OIEC before the OCC in the Company's proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company's proposed wind subscription tariff.

141. **Nevada Power Company, 2010 (Docket No. 10-02009) –** Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC to provide testimony in NPC's Internal Resource Plan to address the ratemaking treatment of the proposed ON Line transmission line.

142. **Entergy Texas Inc., 2010 (PUC Docket No. 37744) –** Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

143. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

144. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.

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145. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

146. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

147. **Nevada Power Company, 2009, (Docket No. 08-12002) -** Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

148. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

149. **Oklahoma Natural Gas Co., 2009 (Cause No. PUD 08-348) –** Participated as an expert witness on witness on behalf of the OIEC before the OCC in ONG's application to establish a Performance Based Rate tariff. Sponsored both written and oral testimony to address the merits of the utility's proposed PBR.

150. **Rocky Mountain Power, 2009 (Docket No. 08-035-38) –** Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

151. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

152. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.

153. **Public Service Company of Oklahoma, 2008 (Cause No. 08-150) –** Participated as an expert witness on behalf of the OIEC before the OCC to address PSO's calculation of its Fuel Clause Adjustment for 2008.

154. **Oklahoma Gas and Electric Company, 2008 (Cause No. PUD 08-059) –** Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

155. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334) –** Participated as an expert witness on behalf of the Cities in EGSI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

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156. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.

157. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447) –** Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO_2 allowances.

158. **Rocky Mountain Power, 2008 (Docket No. 07-035-93) –** Participated as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

159. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

160. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO_2 allowances.

161. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application seeking pre-approval to construct the Red Rock coal plant to address the Company's proposed rider recovery mechanism.

162. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335) –** Participated as an expert witness on behalf of the OIEC before the OCC in ONG's application proposing alternative cost recovery for the Company's ongoing capital expenditures through the proposed Capital Investment Mechanism Rider ("CIM Rider"). Sponsored testimony to address ONG's proposal.

163. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company's use of debt equivalency in the competitive bidding process for new resources.

164. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

165. **Nevada Power Company, 2007, (Docket No. 07-01022) -** Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

166. **Nevada Power Company, 2006, (Docket No. 06-11022) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to

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establish prospective cost-of-service based rates for the power company.

167. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766) –** Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.

168. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676) –** Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities ("ATM"). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.

169. **Nevada Power Company, 2006 (Docket No. 06-06007) –** Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.

170. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516) -** Participated as an expert witness on behalf of the OIEC to review PSO's application for a "used and useful" determination of its proposed peaking facility.

171. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041) –** Participated as an expert witness on behalf of the OIEC in OG&E's application to propose an incentive sharing mechanism for SO_2 allowance proceeds.

172. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177) –** Participated as an expert witness on behalf of the OIEC in Chermac's PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.

173. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140) –** Participated as an expert witness on behalf of the OIEC in OG&E's 2003 and 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, its transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

174. **Nevada Power Company, 2006, (Docket No. 06-01016) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

175. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151) –** Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.

176. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610) –** Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective

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cost-of-service based rates.

177. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participated as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.

178. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754) –** Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO's requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.

179. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564) -** Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:

180. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003)** – Participated as a consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

181. **Nevada Power Company, 2003, (Docket No. 03-10001) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

182. **Nevada Power Company, 2003, (Docket No. 03-11019) -** Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

183. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

184. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226) –** Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.

185. **Nevada Power Company, 2003 (Docket No. 02-5003-5007) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage's 661 Application to leave the system.

186. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing

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business in California.

187. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306) -** Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.

188. **Nevada Power Company, 2003 (Docket No. 03-11019) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility's various customer classes.

189. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L)** – Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.

190. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455) –** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.

191. **Nevada Power Company, 2002 (Docket No. 02-11021) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.

192. **Nevada Power Company, 2002 (Docket No. 01-11029) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company's $928 million deferred energy balances.

193. **Nevada Power Company, 2002 (Docket No. 01-10001) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

194. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L) -** Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.

195. **Southern Union Gas Company, 2001 -** Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of high commodity price spikes during the winter months.

196. **Nevada Power Company, 2001 -** Participated as an expert witness on behalf of the MGM-Mirage,

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Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.

197. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54) -** Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.

198. **Klatt v. Hunt et al., 2000 (ND) -** Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.

199. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020) -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.

200. **Oklahoma Gas and Electric Co., 1999 -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR) proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.

201. **Nevada Power Company, 1999 (Docket No. 99-7035) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.

202. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.

203. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.

204. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023) -** Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada

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(3) the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.

205. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177) -** Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.

206. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214) -** Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.

207. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106) -** Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.

208. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116) -** Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.

209. **Oklahoma Corporation Commission, 1996 -** Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.

210. **Tenkiller Water Company, 1996 -** Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.

211. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134) -** Sponsored written and oral testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.

212. **Enogex, Inc., 1995 (FERC 95-10-000) -** Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.

213. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477) -** Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.

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214. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.

215. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.

216. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190) -** Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.

217. **Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055) -** Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.

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INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 9
IURC CAUSE NO. 45576

DATA REQUEST NO OUCC 9-02

REQUEST

Please provide the amount of Net Operating Loss Carryforward ("NOLC") included in the I&M accounting records on December 31 of each year 2017 through 2020.

RESPONSE

The below chart outlines the accounting records of I&M's NOLC as a result of the Company's participation in the AEP Inc. consolidated federal tax return and the required accounting under GAAP for allocation of the consolidated tax liability under the group's tax allocation agreement for December 31, 2017. The NOLC in years 2018-2020 included in I&Ms accounting records is zero.

	Consolidated	I&M	Affiliates
2017	$20.8M	$4.3M	$16.5M

INDIANA MICHIGAN POWER COMPANY
Municipal Intervenors
DATA REQUEST SET NO. JM DR 1
IURC CAUSE NO. 45576

DATA REQUEST NO JM 1-13

REQUEST

Provide a copy of any income tax sharing agreement that I&M has with its parent company. Admit or deny that I&M has been reimbursed by its parent company for all or some portion of I&M's stand-alone balance of Net Operating Loss Carryforward to date. If admitted, provide the amount that I&M was reimbursed and how these funds were used.

RESPONSE

I&M objects to the request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively sensitive, and/or trade secret. Subject to and without waiver of the foregoing objection, I&M provides the following response with confidential responses being provided pursuant to the non-disclosure agreement between the parties.

Please see JM 1-13 CONFIDENTIAL Attachment 1 for a copy of the tax agreement for allocating consolidated income taxes for AEP Inc. and its consolidated affiliates.

Admit as explained: I&M participates in the AEP consolidated federal return and it's Tax Allocation Agreement. The agreement states that the holding company will provide a payment to any tax loss member equal to "the amount by which the consolidated tax is reduced by including the member's net corporate tax loss in the consolidated tax return." AEP affiliates receiving any payment from the holding company under the tax allocation agreement as the result of tax losses are therefore dependent upon other companies within the consolidated group generating taxable income. Any such payments received by a loss affiliate represents the tax obligation of income affiliates that have been deferred as the result of filing a consolidated return and are not the direct result of the regulated operations of the loss affiliate.

Under the Tax Allocation Agreement I&M has received payments from AEP Inc. as a result of I&M's losses. I&M has a stand-alone Net Operating Loss Carryforward (NOLC) deferred tax asset (DTA) of $165,789,540 as of the 2019 filed tax return. The 2020 return has yet to be filed and is based on income/loss reported on the financial statements, which is $235M of income, resulting in a reduction to the NOLC DTA of ($49,497,801). Years 2021-2022 are forecasted for the test year to be a total of $348M of income, resulting in an additional reduction to the NOLC DTA of ($73,100,499). The total forecasted stand-alone NOL is $43,191,239. Affiliates are reimbursed on an accrual basis as taxes are estimated and quarterly required payments are made to the IRS.

Indiana Michigan Power Company
Short-Term Incentives- Total Company Basis
Annual Projection 2021 and 2022
In Thousands ($000)

2021-2022 I&M O&M Direct Short-Term Incentives	**2021**	**2022**
120 Indiana Michigan Pwr Co - Tran	165.65	167.62
132 Indiana Michigan Pwr Co - Gen	928.52	966.58
170 Indiana Michigan Pwr Co - Dist	2,691.72	2,727.82
190 Indiana Michigan Pwr Co - Nuc	12,775.22	13,162.16
Grand Total	**16,561.10**	**17,024.18**

2021-2022 AEPSC O&M Short-Term Incentives to I&M	**2021**	**2022**
120 Indiana Michigan Pwr Co - Tran	831.50	848.35
132 Indiana Michigan Pwr Co - Gen	1,707.58	1,730.23
170 Indiana Michigan Pwr Co - Dist	1,511.91	1,562.10
190 Indiana Michigan Pwr Co - Nuc	1,674.07	1,707.84
Grand Total	**5,725.05**	**5,848.52**

2021-2022 I&M Capitalized Direct Short-Term Incentives	**2021**	**2022**
120 Indiana Michigan Pwr Co - Tran	236.80	247.92
132 Indiana Michigan Pwr Co - Gen	(14.02)	(12.32)
170 Indiana Michigan Pwr Co - Dist	2,972.26	3,105.50
190 Indiana Michigan Pwr Co - Nuc	505.70	517.19
Grand Total	**3,700.74**	**3,858.29**

2021-2022 AEPSC Capitalized Short-Term Incentives to I&M	**2021**	**2022**
120 Indiana Michigan Pwr Co - Tran	1,002.83	1,064.10
132 Indiana Michigan Pwr Co - Gen	1,464.36	1,474.67
170 Indiana Michigan Pwr Co - Dist	746.76	773.59
190 Indiana Michigan Pwr Co - Nuc	1,069.40	1,115.82
Grand Total	**4,283.35**	**4,428.18**

ARKANSAS PUBLIC SERVICE COMMISSION

ATTORNEY GENERAL'S FOURTH SET OF DATA REQUESTS
DOCKET NO. 19-008-U
DATA REQUEST NO. AG 4-2

COMPANY NAME: SOUTHWESTERN ELECTRIC POWER COMPANY

DATE REQUESTED: 4/18/2019

DATE REQUIRED: 5/3/2019

INFORMATION REQUESTED:

Do any of SWEPCO's short-term incentive plans identified above have threshold earnings levels (e.g. earnings per share) below which all incentives will not be paid? For each plan that has a threshold, please identify the threshold for each year from 2010-2018.

RESPONSE:

For the years 2010 and 2013-2018, all of the Companies' short-term incentive compensation plans, except the Trading & Marketing Plans, included an earnings threshold, which, if not achieved, would have eliminated all short-term incentive awards for such year. for the years 2011 and 2012 all of the Companies' short-term incentive plans, again except the Trading & Marketing Plans, had an earnings threshold that would have eliminated all incentive compensation except for score modifiers, which would have allowed a payout of up to 12.5% of the target award.

Establishing an earnings threshold is a prudent step taken by the Company to protect the interests of customers and other stakeholders in the Company against further exacerbating an already dire financial situation by paying short-term incentive compensation at a time when AEP could ill afford to do so while meeting its commitments to all non-employee stakeholders. It prudently provides such protection in the event AEP experiences a dire financial situation, such as PG&E's financial situation in 2018. The earnings threshold has been consistently set at highly achievable levels and, consequently was achieved in all years in which it existed so it has never had any impact on the Companies' short-term incentive compensation payouts.

The AEP Operating Earnings per Share (Operating EPS) threshold for the 2010 through 2018 period are shown below:

2010	$	2.80
2011	$	3.00
2012	$	3.00
2013	$	3.00
2014	$	3.15
2015	$	3.35
2016	$	3.65
2017	$	3.55
2018	$	3.70

Witness: Jason M. Yoder Title: Dir Regulatory Acctg Svcs

Oklahoma Industrial Energy Consumers
Data Request OIEC-9
Cause No. PUD 2019-00140

9-8 In light of Mr. Halloran's 30 plus years with compensation issues and employment with Mercer and Willis Towers Watson referenced in his testimony, please provide the following additional information:

a. Please describe Mr. Halloran's knowledge of the extent to which Co-op electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

b. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous question.

c. Please describe Mr. Halloran's knowledge of the extent to which municipal electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

d. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous question.

e. Please describe Mr. Halloran's knowledge of the extent to which state-owned electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

f. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous question.

g. Please describe Mr. Halloran's knowledge of the extent to which federal-owned electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

h. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous qnestion.

Response*:

a. In regard to co-op electric utilities, a majority offer short-term incentives, however, less than 10% offer long-term and/or stock-based incentives to eligible employees. Short-term incentives are most commonly based on a combination of individual and/or company performance criteria (based on a variety of metrics which vary by provider, most commonly based on a combination of financial, availability/reliability, and safety metrics). These data are based on 32 electric utility co-ops included in Mercer's Research Library.

b, d, f, h. The information provided in these responses are based on data obtained from utility compensation surveys and client data contained in Mercer's Research Library. Mercer's Research Library has over 600 compensation surveys, the large majority of which are proprietary and confidential and/or obtained via non-disclosure agreements and therefore unfortunately cannot be provided in whole or in part.

c. Incentives are less common at municipal electric utilities - - less than 20% offer short-term incentives and less than 10% provide long-term and/or stock-based incentives to eligible employees. Like the co-ops, short-term incentives (where provided) are based on a combination of individual and/or company performance criteria (most commonly, a combination of financial, availability/reliability, and safety metrics). This information was obtained from 29 municipal electric utility organizations included in Mercer's Research Library

e. Similarly, roughly 25% of state-owned electric utilities offer short-term incentives (again, based on a combination of individual and/or company performance metrics, most commonly a combination of financial, availability/reliability, and safety metrics). However, based on the data in our Research Library, we are not aware of any state-owned electric utilities that offer long-term and/or stock-based incentives. This information is based on a sample of roughly 20 state-owned electric utilities in Mercer's Research Library.

g. To the best of our knowledge, there are a very small number of federal-owned electric utilities (e.g., Tennessee Valley Authority). Based on data contained within Mercer's Research Library, we understand that none offer long-term/stock-based incentives and only one has a short-term incentive program. Given the small sample (i.e., one company), we cannot provide any details regarding the incentive plan design but would say that in general, it is not all that dissimilar than what is described on the prior page).

Response provided by:	Mike Halloran
Response provided on:	March 5, 2019
Contact & Phone No:	Jill Butson 405-553-3285

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Industrial Energy Consumers
Data Request OIEC-9
Cause No. PUD 2019-00140

9-8 In light of Mr. Halloran's 30 plus years with compensation issues and employment with Mercer and Willis Towers Watson referenced in his testimony, please provide the following additional information:

a. Please describe Mr. Halloran's knowledge of the extent to which Co-op electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

b. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous question.

c. Please describe Mr. Halloran's knowledge of the extent to which municipal electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

d. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous question.

e. Please describe Mr. Halloran's knowledge of the extent to which state-owned electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

f. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous question.

g. Please describe Mr. Halloran's knowledge of the extent to which federal-owned electric utilities provide the following types of compensation to their employees: (1) short-term incentives, (2) short-term financial-based incentives, (3) long term incentives and (4) stock-based incentives.

h. Please provide any information available to Mercer that supports Mr. Halloran's response to the previous qnestion.

Response*:

a. In regard to co-op electric utilities, a majority offer short-term incentives, however, less than 10% offer long-term and/or stock-based incentives to eligible employees. Short-term incentives are most commonly based on a combination of individual and/or company performance criteria (based on a variety of metrics which vary by provider, most commonly based on a combination of financial, availability/reliability, and safety metrics). These data are based on 32 electric utility co-ops included in Mercer's Research Library.

Indiana Michigan Power Company
O&M Long-Term Incentives- Total Company Basis
Projected January 2021 - December 31, 2022
In Thousands ($000)

Indiana Michigan Power Company
Cause No. 45576
OUCC 5-2 Attachment 1

2021-2022 I&M O&M Direct Long-Term Incentives	2021	2022
Performance Stock Incentive	3.24	3.48
Restricted Stock Units	0.55	0.55
120 Indiana Michigan Pwr Co - Tran	**3.79**	**4.03**
Performance Stock Incentive	104.67	109.68
Restricted Stock Units	27.49	28.17
132 Indiana Michigan Pwr Co - Gen	**132.16**	**137.85**
Performance Stock Incentive	355.64	361.23
Restricted Stock Units	93.33	93.22
170 Indiana Michigan Pwr Co - Dist	**448.97**	**454.45**
Performance Stock Incentive	1,993.98	2,032.18
Restricted Stock Units	1,118.96	1,141.66
190 Indiana Michigan Pwr Co - Nuc	**3,112.94**	**3,173.84**
Grand Total	**3,697.86**	**3,770.17**

2021-2022 AEPSC O&M Long-Term Incentives to I&M	2021	2022
Performance Stock Incentive	313.42	320.45
Restricted Stock Units	106.23	107.60
120 Indiana Michigan Pwr Co - Tran	**419.65**	**428.05**
Performance Stock Incentive	694.51	704.04
Restricted Stock Units	249.69	251.75
132 Indiana Michigan Pwr Co - Gen	**944.20**	**955.78**
Performance Stock Incentive	888.40	919.18
Restricted Stock Units	263.29	269.23
170 Indiana Michigan Pwr Co - Dist	**1,151.68**	**1,188.41**
Performance Stock Incentive	1,221.74	1,257.54
Restricted Stock Units	323.81	326.54
190 Indiana Michigan Pwr Co - Nuc	**1,545.55**	**1,584.08**
Grand Total	**4,061.08**	**4,156.32**

Number of employees including vacancies and open positions	2,145	2,105

Indiana Michigan Power Company
O&M Percentage of Total Payroll
Annual Projection 2021 and 2022
In Thousands ($000)

Projected Payroll: I&M Direct and AEPSC to I&M	2021	2022
Total O&M Payroll	185,796	192,616
Total Payroll	282,021	288,522
Percent of O&M to Total Payroll	65.88%	66.76%

Indiana Michigan Power Company
Cash Compensation
2022 Projection (Total Company)
In Thousands ($000)

2022 Total Cash Compensation			Paid Cash Compensation				
					Incentive or Bonus		
Category	**Month**	**Total FTEs**	**Base Wages and**	**Overtime**	**Short-Term**	**Long-Term**	**Total**
Regular Employees	January		21,660	1,266	2,129	418	25,474
	February		21,997	1,238	2,645	871	26,751
	March		22,529	1,366	2,645	998	27,537
	April		23,550	1,488	2,637	867	28,542
	May		23,550	1,384	2,638	867	28,439
	June		22,364	1,436	2,639	993	27,433
	July		22,540	1,458	2,638	868	27,503
	August		22,878	1,225	2,638	867	27,608
	September		23,318	1,329	2,638	993	28,277
	October		23,309	1,198	2,637	867	28,011
	November		22,259	1,148	2,637	867	26,911
	December		22,126	1,673	2,639	993	27,432
	Total	**2,105**	**272,080**	**16,210**	**31,159**	**10,469**	**329,918**

2022 I&M Direct Cash Compensation			Paid Cash Compensation				
					Incentive or Bonus		
Category	**Month**	**Total FTEs**	**Base Wages and**	**Overtime**	**Short-Term**	**Long-Term**	**Total**
Regular Employees	January		15,411	1,201	1,452	203	18,267
	February		15,781	1,173	1,766	359	19,079
	March		16,309	1,300	1,767	359	19,735
	April		17,211	1,423	1,766	359	20,759
	May		17,211	1,319	1,766	359	20,655
	June		16,023	1,370	1,767	359	19,520
	July		16,201	1,393	1,766	359	19,719
	August		16,535	1,160	1,766	359	19,820
	September		16,975	1,264	1,767	359	20,365
	October		16,975	1,134	1,766	359	20,234
	November		15,926	1,084	1,766	359	19,134
	December		15,794	1,608	1,767	359	19,528
	Total	**2,105**	**196,352**	**15,428**	**20,882**	**4,153**	**236,815**

2022 AEPSC Cash Compensation to I&M			Paid Cash Compensation				
					Incentive or Bonus		
Category	**Month**	**Total FTEs**	**Base Wages and**	**Overtime**	**Short-Term**	**Long-Term**	**Total**
Regular Employees	January		6,249	66	677	215	7,207
	February		6,216	66	878	512	7,672
	March		6,220	66	878	639	7,802
	April		6,339	65	871	508	7,784
	May		6,339	65	871	508	7,784
	June		6,342	65	872	634	7,913
	July		6,339	65	872	509	7,784
	August		6,342	65	872	508	7,787
	September		6,342	65	871	633	7,912
	October		6,333	65	871	508	7,777
	November		6,333	64	871	508	7,777
	December		6,333	65	872	634	7,904
	Total	**n/a**	**75,727**	**782**	**10,277**	**6,317**	**93,103**

Total FTEs include vacancies and open positions.

Indiana Michigan Power Company
Breakout of Payroll Expense
For the Years 2016 through 2020 (Total Company)

2020 Year

Average Number of Employees: 2,110

	Capital	O&M	Other	Total
Overtime Hours				415,901
Straight time	$ 50,075,326	$ 131,147,783	$ 13,047,807	$ 194,270,917
Overtime Pay	5,203,128	16,082,057	2,877,494	24,162,679
ST Incentive - ICP	9,708,419	26,512,499	1,490,166	37,711,084
LT Incentive - PSI	570,895	2,510,596	114,167	3,195,659
LT Incentive - RSU	188,672	1,111,371	52,947	1,352,990
Other	1,113,904	8,177,180	121,534	9,412,618

2019 Year

Average Number of Employees: 2,165

	Capital	O&M	Other	Total
Overtime Hours				543,794
Straight time	$ 43,213,077	$ 130,575,048	$ 12,132,900	$ 185,921,025
Overtime Pay	6,035,994	21,303,581	2,762,576	30,102,151
ST Incentive - ICP	6,179,757	27,479,939	2,486,686	36,146,383
LT Incentive - PSI	478,826	2,317,620	100,918	2,897,364
LT Incentive - RSU	174,327	967,948	40,702	1,182,977
Other	232,768	2,408,812	26,475	2,668,056

2018 Year

Average Number of Employees: 2,199

	Capital	O&M	Other	Total
Overtime Hours				540,236
Straight time	$ 35,753,841	$ 134,133,258	$ 11,412,443	$ 181,299,541
Overtime Pay	5,104,276	17,248,609	3,251,695	25,604,580
ST Incentive - ICP	5,804,481	22,416,864	1,597,159	29,818,504
LT Incentive - PSI	533,810	2,587,213	132,931	3,253,955
LT Incentive - RSU	171,664	963,439	54,083	1,189,186
Other	4,856,218	(3,312,974)	24,146	1,567,389

2017 Year

Average Number of Employees: 2,212

	Capital	O&M	Other	Total
Overtime Hours				535,950
Straight time	$ 35,595,668	$ 132,552,978	$ 10,795,939	$ 178,944,586
Overtime Pay	$ 5,885,937	$ 17,152,099	$ 2,859,529	$ 25,897,565
ST Incentive - ICP	$ 3,666,645	$ 16,891,877	$ 1,086,336	$ 21,644,858
LT Incentive - PSI	$ 747,011	$ 3,837,721	$ 187,311	$ 4,772,044
LT Incentive - RSU	$ 129,804	$ 627,160	$ 33,857	$ 790,821
Other	$ 4,468,891	$ (2,536,166)	$ 67,956	$ 2,000,681

2016 Year

Average Number of Employees: 2,230

	Capital	O&M	Other	Total
Overtime Hours				597,474
Straight time	$ 32,351,423	$ 133,126,066	$ 10,618,117	$ 176,095,606
Overtime Pay	6,567,904	20,032,118	1,998,274	28,598,296
ST Incentive - ICP	6,156,292	25,862,306	1,675,254	33,693,851
LT Incentive - PSI	636,334	3,090,550	113,234	3,840,118
LT Incentive - RSU	115,169	493,481	20,122	628,771
Other	3,440,514	(1,309,080)	24,382	2,155,815

Indiana Michigan Power Company
Cash Compensation
Budgeted from 2016 through 2020
In Thousands ($000) (Total Company)

2016-2020Total Cash Compensation			Paid Cash Compensation				
					Incentive or Bonus		
Category	Year	Total FTEs	Base Wages and Salaries	Overtime	Short-Term	Long-Term	Total
Regular Employees	2016	2,301	233,065	15,686	31,159	8,187	288,096
	2017	2,329	249,664	16,784	27,867	11,015	305,329
	2018	2,336	266,067	16,936	29,830	12,121	324,954
	2019	2,305	265,679	16,638	30,105	12,295	324,716
	2020	2,348	272,406	16,680	30,762	11,239	331,087

2016-2020I&M Direct Cash Compensation			Paid Cash Compensation				
					Incentive or Bonus		
Category	Year	Total FTEs	Base Wages and Salaries	Overtime	Short-Term	Long-Term	Total
Regular Employees	2016	2,301	182,790	14,940	22,887	4,010	224,628
	2017	2,329	197,563	15,991	20,333	4,317	238,204
	2018	2,336	201,213	15,544	20,372	4,407	241,536
	2019	2,305	198,819	15,724	20,846	4,496	239,884
	2020	2,348	200,616	15,939	21,193	3,565	241,313

2016-2020 AEPSC Cash Compensation to I&M			Paid Cash Compensation				
					Incentive or Bonus		
Category	Year	Total FTEs	Base Wages and Salaries	Overtime	Short-Term	Long-Term	Total
Regular Employees	2016	n/a	50,275	745	8,272	4,177	63,469
	2017	n/a	52,101	793	7,534	6,698	67,126
	2018	n/a	64,854	1,391	9,459	7,714	83,418
	2019	n/a	66,860	914	9,260	7,799	84,833
	2020	n/a	71,790	740	9,569	7,674	89,774

Total FTEs include vacancies and open positions.

Indiana Michigan Power Company
Monthly Breakout of Payroll Expense
For the Years 2020 and 2021 through June (Total Company)

	PayType	Capital	O&M	Other	Total
2020					
January	Straight time	4,621,727	12,717,114	1,284,571	18,623,413
2,146 Employees	Overtime	382,871	1,368,562	214,000	1,965,433
24,165 OT hours	ST Incentive - ICP	296,160	369,503	142,416	808,078
	LT Incentive - PSI	37,073	132,978	6,924	176,975
	LT Incentive - RSU	15,923	90,085	3,943	109,951
	Other	129,581	896,711	1,582	1,027,874
January Total		5,483,334	15,574,953	1,653,436	22,711,723
February	Straight time	3,753,855	10,346,000	1,026,288	15,126,142
2,144 Employees	Overtime	256,920	686,264	101,346	1,044,530
20,499 OT hours	ST Incentive - ICP	380,790	1,360,597	105,226	1,846,613
	LT Incentive - PSI	29,046	124,561	6,072	159,679
	LT Incentive - RSU	16,106	90,762	4,107	110,976
	Other	18,911	65,172	1,256	85,339
February Total		4,455,628	12,673,355	1,244,296	18,373,279
March	Straight time	3,900,092	10,699,381	1,027,321	15,626,794
2,147 Employees	Overtime	306,507	822,315	142,389	1,271,211
25,783 OT hours	ST Incentive - ICP	534,247	(2,733,182)	84,046	(2,114,890)
	LT Incentive - PSI	46,211	(54,918)	9,595	888
	LT Incentive - RSU	20,815	107,814	5,099	133,729
	Other	10,758	129,925	1,326	142,010
March Total		4,818,630	8,971,335	1,269,776	15,059,742
April	Straight time	3,663,582	11,475,525	964,967	16,104,074
2,132 Employees	Overtime	327,206	906,821	108,778	1,342,804
25,873 OT hours	ST Incentive - ICP	(1,117,629)	58,978	(308,163)	(1,366,814)
	LT Incentive - PSI	13,692	159,860	2,295	175,847
	LT Incentive - RSU	19,751	108,786	4,659	133,195
	Other	262,672	132,189	702	395,564
April Total		3,169,273	12,842,159	773,238	16,784,671
May	Straight time	3,889,836	11,365,375	1,021,866	16,277,077
2,128 Employees	Overtime	236,383	1,136,612	76,573	1,449,568
30,085 OT hours	ST Incentive - ICP	190,190	679,807	52,798	922,795
	LT Incentive - PSI	46,988	202,681	9,421	259,090
	LT Incentive - RSU	15,700	93,945	4,030	113,675
	Other	25,100	17,723	676	43,499
May Total		4,404,197	13,496,142	1,165,365	19,065,704
June	Straight time	4,534,904	9,914,372	1,319,790	15,769,066
2,118 Employees	Overtime	361,294	999,254	95,517	1,456,065
27,713 OT hours	ST Incentive - ICP	44,032	144,090	11,038	199,160
	LT Incentive - PSI	47,164	285,975	9,806	342,945
	LT Incentive - RSU	16,249	94,557	4,391	115,196
	Other	27,086	25,436	552	53,074
June Total		5,030,729	11,463,684	1,441,094	17,935,507
July	Straight time	5,555,027	13,588,526	1,419,565	20,563,118
2,107 Employees	Overtime	427,507	1,356,273	146,362	1,930,142
26,094 OT hours	ST Incentive - ICP	359,899	1,227,899	95,333	1,683,132
	LT Incentive - PSI	41,033	169,926	8,165	219,124
	LT Incentive - RSU	16,750	94,969	4,057	115,776
	Other	24,655	651,644	892	677,190
July Total		6,424,869	17,089,237	1,674,374	25,188,481
August	Straight time	3,647,039	9,450,499	978,067	14,075,605
2,092 Employees	Overtime	426,176	1,047,054	554,618	2,027,848
44,897 OT hours	ST Incentive - ICP	113,898	398,795	45,805	558,498
	LT Incentive - PSI	36,660	175,443	14,141	226,244
	LT Incentive - RSU	13,582	93,910	5,328	112,819
	Other	10,308	298,205	2,146	310,660
August Total		4,247,663	11,463,905	1,600,106	17,311,674
September	Straight time	3,666,276	9,232,719	902,970	13,801,965
2,079 Employees	Overtime	607,967	2,054,246	227,479	2,889,692
62,374 OT hours	ST Incentive - ICP	1,125,263	4,124,268	366,758	5,616,289
	LT Incentive - PSI	56,250	310,588	14,721	381,559
	LT Incentive - RSU	13,609	96,501	4,904	115,013
	Other	50,551	5,352,882	6,997	5,410,431
September Total		5,519,916	21,171,204	1,523,830	28,214,949

Indiana Michigan Power Company
Monthly Breakout of Payroll Expense
For the Years 2020 and 2021 through June (Total Company)

	PayType	Capital	O&M	Other	Total
October	Straight time	4,304,925	9,834,000	960,452	15,099,377
2,073 Employees	Overtime	436,834	3,554,422	665,148	4,656,404
66,653 OT hours	ST Incentive - ICP	436,758	1,615,958	173,609	2,226,325
	LT Incentive - PSI	35,018	185,243	12,102	232,363
	LT Incentive - RSU	10,351	81,530	4,795	96,676
	Other	5,368	17,877	2,490	25,735
October Total		5,229,255	15,289,030	1,818,596	22,336,880
November	Straight time	4,414,835	8,906,112	954,534	14,275,481
2,070 Employees	Overtime	442,377	1,025,735	376,688	1,844,801
36,638 OT hours	ST Incentive - ICP	885,008	2,509,373	155,688	3,550,069
	LT Incentive - PSI	43,291	178,268	9,929	231,487
	LT Incentive - RSU	14,457	78,869	4,787	98,113
	Other	5,879	55,703	1,233	62,815
November Total		5,805,848	12,754,059	1,502,860	20,062,767
December	Straight time	4,123,229	13,618,159	1,187,415	18,928,804
2,059 Employees	Overtime	991,086	1,124,500	168,594	2,284,180
25,128 OT hours	ST Incentive - ICP	6,459,803	16,756,415	565,611	23,781,829
	LT Incentive - PSI	138,469	639,993	10,997	789,459
	LT Incentive - RSU	15,380	79,645	2,847	97,871
	Other	543,034	533,712	101,681	1,178,427
December Total		12,271,001	32,752,423	2,037,146	47,060,570
2021					
January	Straight time	3,548,030	9,837,839	882,847	14,268,715
2,051 Employees	Overtime	470,499	1,043,596	127,836	1,641,931
34,055 OT hours	ST Incentive - ICP	(933,332)	1,633,326	674,801	1,374,795
	LT Incentive - PSI	19,161	67,721	10,026	96,909
	LT Incentive - RSU	14,807	79,513	2,895	97,215
	Other	7,712	690,813	1,288	699,813
January Total		3,126,877	13,352,808	1,699,693	18,179,378
February	Straight time	3,613,368	10,513,923	994,916	15,122,208
2,047 Employees	Overtime	544,514	1,317,142	154,494	2,016,150
49,649 OT hours	ST Incentive - ICP	357,370	1,253,102	93,608	1,704,080
	LT Incentive - PSI	31,106	139,094	4,710	174,910
	LT Incentive - RSU	12,507	81,736	3,006	97,250
	Other	177,252	136,779	1,898	315,928
February Total		4,736,117	13,441,776	1,252,633	19,430,526
March	Straight time	3,873,701	10,064,353	1,008,180	14,946,235
2,025 Employees	Overtime	603,037	1,157,707	135,399	1,896,143
22,853 OT hours	ST Incentive - ICP	84,653	(303,697)	101,762	(117,281)
	LT Incentive - PSI	47,389	228,090	7,771	283,250
	LT Incentive - RSU	17,819	98,343	3,792	119,954
	Other	36,432	(364,929)	2,974	(325,523)
March Total		4,663,032	10,879,867	1,259,879	16,802,778
April	Straight time	3,737,771	9,721,886	890,782	14,350,439
2,014 Employees	Overtime	305,046	1,428,857	88,006	1,821,910
50,518 OT hours	ST Incentive - ICP	383,479	1,278,666	90,433	1,752,578
	LT Incentive - PSI	49,018	214,562	7,912	271,492
	LT Incentive - RSU	17,367	100,027	4,105	121,499
	Other	8,589	11,297	(239)	19,646
April Total		4,501,270	12,755,295	1,080,998	18,337,563
May	Straight time	3,634,529	10,967,272	947,535	15,549,335
2,019 Employees	Overtime	406,424	3,736,992	234,552	4,377,967
58,930 OT hours	ST Incentive - ICP	342,861	1,309,333	95,753	1,747,947
	LT Incentive - PSI	45,807	239,661	8,885	294,352
	LT Incentive - RSU	10,809	71,014	2,604	84,427
	Other	7,421	22,649	781	30,851
May Total		4,447,850	16,346,921	1,290,108	22,084,880
June	Straight time	3,654,171	9,312,876	879,841	13,846,889
2,032 Employees	Overtime	611,434	835,998	135,700	1,583,133
40,581 OT hours	ST Incentive - ICP	393,694	1,387,292	105,470	1,886,456
	LT Incentive - PSI	50,532	264,074	8,381	322,987
	LT Incentive - RSU	12,801	70,610	2,484	85,895
	Other	3,934	46,840	494	51,268
June Total		4,726,567	11,917,690	1,132,370	17,776,627

FERC Income Stmt
2016 Control Budget
($000)

2016 Control Budget	Year 2016
Indiana Michigan Power	
UTILITY OPERATING INCOME	
(440) Residential Sales	619,981
(442) Commercial Sales	439,198
(442) Industrial Sales	502,006
(444) Public Street & Highway Lighting	7,198
(445) Other Sales to Public Authorities	
Unclassified Goal-Seek Revenues	
TOTAL Sales to Ultimate Customers	**1,568,383**
(447) Sales for Resale	465,950
TOTAL Sales of Electricity	**2,034,333**
Less: (449.1) Provision for Rate Refunds	
TOTAL Revenues Net of Prov. for Refunds	**2,034,333**
Other Operating Revenues	
(450) Forfeited Discounts	4,832
(451) Misc. Service Revenues	4,571
(454) Rent from Electric Property	7,567
(456) Other Electric Revenues	43,798
(457) Services Rendered to Associated Cos.	
(458) Services Rendered to Non-Associated Cos.	
Total Other Operating Revenues	**60,768**
Total Electric Operating Revenues (400)	**2,095,101**
OPERATING EXPENSES	
Operation & Maintenance Details	
1. POWER PRODUCTION EXPENSES	
A. Steam Power Generation	
Operation	
(500) Operation Supervision & Engineering	3,714
(501) Fuel	179,441
(502) Steam Expense	15,103
(505) Electric Expense	150
(506) Misc Steam Power Expense	7,383
(507) Rents	70,147
(508) IPP Admin	
(509) Allowances	1,918
TOTAL Operation - Steam	**277,857**
Maintenance	
(510) Maint Supervision and Engineering	1,702
(511) Maint of Structures	25
(512) Maint of Boiler Plant	11,325
(513) Maint of Electric Plant	492
(514) Maint of Misc Steam Plant	97
(515) Maint of Steam Production Plant	
TOTAL Maintenance - Steam	**13,642**

FERC Income Stmt
2016 Control Budget
($000)

2016 Control Budget	Year 2016
Indiana Michigan Power	
TOTAL Power Production Expense - Steam Power	**291,499**
B. Nuclear Power Generation	
Operation	
(517) Operation Supervision and Engineering	11,174
(518) Fuel	134,939
(519) Coolants and Water	7,704
(520) Steam Expense	7,991
(523) Electric Expenses	4,125
(524) Misc Nuclear Power Expenses	81,566
(525) Rents	
TOTAL Operation - Nuclear	**247,498**
Maintenance	
(528) Maint Supervision and Engineering	3,783
(529) Maint of Structures	1,777
(530) Maint of Reactor Plant Equipment	42,588
(531) Maint of Electric Plant	5,763
(532) Maint of Misc Nuclear Plant	71,380
TOTAL Maintenance - Nuclear	**125,291**
TOTAL Power Production Expense - Nuclear Power	**372,789**
C. Hydraulic Power Generation	
Operation	
(535) Operation Supervision and Engineering	
(536) Water for Power	
(537) Hydraulic Expenses	
(538) Electric Expenses	
(539) Misc Hydraulic Power Generation Expenses	1,469
(540) Rents	
TOTAL Operation - Hyro	**1,469**
Maintenance	
(541) Maint Supervision and Engineering	
(542) Maint of Structures	
(543) Maint of Reservoirs, Dams & Waterways	
(544) Maint of Electric Plant	1,497
(545) Maint of Misc Hydraulic Plant	
TOTAL Maintenance - Hydo	**1,497**
TOTAL Power Production Expenses - Hydraulic Power	**2,965**
D. Other Power Generation	
Operation	
(546) Operation Supervision and Engineering	
(547) Fuel	
(548) Generation Expenses	
(549) Misc Other Power Generation Expenses	
(550) Rents Gas Turbines	
(858) Trans By Others - Commodity	
TOTAL Operation - Other Power	
Maintenance	
(551) Maint Supervision and Engineering	

FERC Income Stmt
2016 Control Budget
($000)

2016 Control Budget	Year 2016
Indiana Michigan Power	
(552) Maint of Structures	
(553) Maint of Generating and Electric Plant	
(554) Maint of Misc Other Power Gen Plant	
TOTAL Maintenance - Other Power	
TOTAL Power Production Expenses - Other Power	
E. Other Power Supply Expenses	
(555) Purchased Power	435,654
(556) System Control & Load Dispatching	1,297
(557) Other Expenses	1,897
TOTAL OTher Power Supply Exp	**438,847**
Total Power Production Expenses	**1,106,100**
2. TRANSMISSION EXPENSES	
Operation	
(560) Operation Supervision and Engineering	5,276
(561) Load Displatching	6,916
(562) Station Expenses	
(563) Overhead Lines Expenses	70
(564) Underground Lines Expenses	
(565) Transmission of Electricity by Others	65,497
(566) Misc Transmission Expenses	2,104
(567) Rents	
TOTAL Operation - Transm	**79,863**
Maintenance	
(568) Maint Supervision and Engineering	
(569) Maint of Structures	455
(570) Maint of Station Equipment	4,894
(571) Maint of Overhead Lines	5,375
(572) Maint of Underground Lines	
(573) Maint of Misc Transmission Plant	
TOTAL Maintenance - Transm	**10,724**
TOTAL Transmission Expenses	**90,587**
3. REGIONAL MARKET EXPENSES	
Operation	
(575.7) Market Facilitation	3,958
TOTAL Operation - Regional Market	3,958
Maintenance	
(576.x) Maintenance of Facility	
TOTAL Maintenance - Regional Market	
TOTAL Regional Transmission and Market Expenses	3,958
4. DISTRIBUTION EXPENSES	
Operation	
(580) Operation Supervision and Engineering	2,960
(581) Load Dispatching	1,149
(582) Station Expenses	
(583) Overhead Lines Expenses	(166)
(584) Underground Lines Expenses	4,252
(585) Street Lighting & Signal System Expenses	

FERC Income Stmt
2016 Control Budget
($000)

2016 Control Budget	Year 2016
Indiana Michigan Power	
(586) Meter Expenses	775
(587) Customer Installations Expenses	
(588) Misc Distr Expenses	15,287
(589) Rents	1,455
TOTAL Operation - Distr	**25,711**
Maintenance	
(590) Maint Supervision and Engineering	29
(591) Maint of Structures	
(592) Maint of Station Equipment	2,310
(593) Maint of Overhead Lines	30,972
(594) Maint of Underground Lines	1,012
(595) Maint of Line Transformers	204
(596) Maint of Street Lighting & Signal Systems	
(597) Maint of Meters	282
(598) Maint of Misc Distr Plant	180
TOTAL Maintenance - Distr	**34,988**
TOTAL Distribution Expenses	**60,699**
5. CUSTOMER ACCOUNTS EXPENSES	
Operation	
(901) Supervision	969
(902) Meter Reading Expenses	2,446
(903) Customer Records & Collection Expenses	11,158
(904) Uncollectible Accounts	
(905) Misc Customer Accounts Expenses	145
TOTAL Customer Accounts Expenses	**14,717**
6. CUSTOMER SERVICE & INFORMATION EXPENSES	
Operation	
(907) Customer Service Expenses	1,039
(908) Customer Assistance Expenses	26,419
(909) Informational and Instructional Expenses	35
(910) Misc Customer Service and Informational Expenses	
TOTAL Cust Service & Info Expenses	**27,493**
7. SALES EXPENSES	
Operation	
(911) Supervision	
(912) Demonstrating and Selling Expenses	389
(913) Advertising Expenses	
(916) Miscellaneous Sales Expenses	
TOTAL Sales Expenses	**389**
8. ADMINISTRATIVE & GENERAL EXPENSES	
Operation	
(920) Administrative and General Salaries	41,196
(921) Office Supplies and Expenses	3,818
(Less) (922) Admin Expense Transferred-Credit	3,540
(923) Outside Services Employed	10,652
(924) Property Insurance	3,538
(925) Injuries and Damages	7,558

FERC Income Stmt
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2016 Control Budget	Year 2016
Indiana Michigan Power	
(926) Employee Pensions and Benefits	31,111
(927) Franchise Requirements	
(928) Regulatory Commission Expenses	14,021
(Less) (929) Duplicate Charges-Credit	
(930.1) General Advertising Expenses	73
(930.2) Misc General Expenses	4,481
(931) Rents	5,736
TOTAL Operation - A&G	**118,642**
Maintenance	
(935) Maintenance of General Plant	5,116
TOTAL Admin & General Expenses	123,759
TOTAL Electric Oper and Maint Expenses	1,427,702
Additional O&M Ledger Accounts:	
Operation Expenses (401)	1,236,445
Maintenance Expenses (402)	191,257
Depreciation Expense (403.0 & 403.1002)	157,911
Deprec Exp for Asset Retirement (403.1)	8,736
Amort & Depl of Utility Plant (404-405)	22,547
Amort of Utility Plant Acq Adj (406)	
Regulatory Debits (407.3)	(1,907)
(Less) Regulatory Credits (407.4)	
Taxes Other Than Income (408.1)	94,215
Income Taxes - Federal (409.1)	(37,653)
Income Taxes - Other (409.1)	9,018
Provision for Deferred Income Taxes (410.1)	128,194
(Less) Prov for Deferred Income Taxes-CR (411.1)	
Investment Tax Credit Adj - Net (411.4)	(4,724)
(Less) Gains from Disp. of Utility Plant (411.6)	
Losses from Disp. of Utility Plant (411.7)	
(Less) Gains from Disposition of Allowances (411.8)	388
Losses from Disposition of Allowances (411.9)	
Accretion Expense (411.10)	2,859
TOTAL Utility Operating Expenses	1,806,508
Net Utility Operating Income	288,592
Other Income	
Rev Merchandising, Jobing & Contract Work (415)	
(Less) Costs & Exp of Merch, Jobing & Contract Work (416)	
Revenues from Nonutility Operations (417)	64,178
(Less) Expenses of Nonutility Operations (417.1)	58,520
Nonoperating Rental Income (418)	306
Equity in Earnings of Subsidiary Cos (418.1)	
Interest and Dividend Income (419)	1,726
Allowance for Other Funds Used During Constr (419.1)	13,559
Misc Nonoperating Income (421)	2,759

FERC Income Stmt
2016 Control Budget
($000)

2016 Control Budget	Year 2016
Indiana Michigan Power	
Gain on Disposition of Property (421.1)	
TOTAL Other Income	**24,007**
Other Deductions	
Loss on Disposition of Property (421.2)	
Misc Amortization (425)	
Donations (426.1)	258
Life Insurance (426.2)	
Penalties (426.3)	
Exp for Certain Civic, Political & Related Activities (426.4)	1,240
Other Deductions (426.5)	10,987
TOTAL Other Deductions	**12,485**
Taxes Applicable to Other Income & Deductions	
Taxes Other Than Income Taxes (408.2)	1,911
Income Taxes - Federal (409.2)	(1,382)
Income Taxes - Other (409.2)	(198)
Provision for Deferred Inc. Taxes (410.2)	
(Less) Provision for Deferred Inc Taxes-Cr. (411.2)	
Investment Tax Credit Adj-Net (411.5)	
TOTAL Taxes on Other Income and Deductions	**331**
Net Other Income and Deductions	**11,191**
Interest Charges	
Interest on Long-Term Debt (427)	91,706
Amort of Debt Disc. & Expense (428)	1,323
Amort of Loss on Reacquired Debt (428.1)	1,045
(Less) Amort of Premium on Debt-Credit (429)	
(Less) Amort of Gain on Reacquired Debt-Credit (429.1)	
Interest on Debt to Assoc Cos (430)	1,340
Other Interest Expense (431)	11,667
(Less) Allowance for Borrowed Funds Used During Constr-Cr. (432)	7,098
Net Interest Charges	**99,984**
Income Before Extraordinary Items	**199,800**
Extraordinary Items	
Extraordinary Income (434)	
(Less) Extraordinary Deductions (435)	
Net Extraordinary Items	
Income Taxes-Federal & Other (409.3)	
Extraordinary Items After Taxes	
Net Income	199,800
(Less) Preferred Dividends	
Balance For Common	**199,800**
Operation Expense, excld Fuel & Purchased Power	482,453
Maintenance Expense	191,257

FERC Income Stmt
2017 Control Budget
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2017 Control Budget	Year 2017
Indiana Michigan Power	
UTILITY OPERATING INCOME	
(440) Residential Sales	611,412
(442) Commercial Sales	450,233
(442) Industrial Sales	554,391
(444) Public Street & Highway Lighting	7,840
(445) Other Sales to Public Authorities	
Unclassified Goal-Seek Revenues	
TOTAL Sales to Ultimate Customers	**1,623,875**
(447) Sales for Resale	425,854
TOTAL Sales of Electricity	**2,049,729**
Less: (449.1) Provision for Rate Refunds	
TOTAL Revenues Net of Prov. for Refunds	**2,049,729**
Other Operating Revenues	
(450) Forfeited Discounts	5,000
(451) Misc. Service Revenues	4,800
(454) Rent from Electric Property	8,356
(456) Other Electric Revenues	34,339
(457) Services Rendered to Associated Cos.	
(458) Services Rendered to Non-Associated Cos.	
Total Other Operating Revenues	**52,495**
Total Electric Operating Revenues (400)	**2,102,225**
OPERATING EXPENSES	
Operation & Maintenance Details	
1. POWER PRODUCTION EXPENSES	
A. Steam Power Generation	
Operation	
(500) Operation Supervision & Engineering	4,389
(501) Fuel	149,991
(502) Steam Expense	19,462
(505) Electric Expense	115
(506) Misc Steam Power Expense	7,524
(507) Rents	70,159
(508) IPP Admin	
(509) Allowances	1,533
TOTAL Operation - Steam	**253,175**
Maintenance	
(510) Maint Supervision and Engineering	2,108
(511) Maint of Structures	23
(512) Maint of Boiler Plant	16,339
(513) Maint of Electric Plant	1,841
(514) Maint of Misc Steam Plant	73
(515) Maint of Steam Production Plant	
TOTAL Maintenance - Steam	**20,384**

FERC Income Stmt
2017 Control Budget
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2017 Control Budget	Year 2017
Indiana Michigan Power	
TOTAL Power Production Expense - Steam Power	**273,559**
B. Nuclear Power Generation	
Operation	
(517) Operation Supervision and Engineering	11,883
(518) Fuel	124,387
(519) Coolants and Water	7,928
(520) Steam Expense	8,568
(523) Electric Expenses	4,104
(524) Misc Nuclear Power Expenses	80,893
(525) Rents	
TOTAL Operation - Nuclear	**237,761**
Maintenance	
(528) Maint Supervision and Engineering	3,777
(529) Maint of Structures	1,711
(530) Maint of Reactor Plant Equipment	(17,858)
(531) Maint of Electric Plant	5,787
(532) Maint of Misc Nuclear Plant	146,542
TOTAL Maintenance - Nuclear	**139,959**
TOTAL Power Production Expense - Nuclear Power	**377,720**
C. Hydraulic Power Generation	
Operation	
(535) Operation Supervision and Engineering	
(536) Water for Power	
(537) Hydraulic Expenses	
(538) Electric Expenses	
(539) Misc Hydraulic Power Generation Expenses	2,129
(540) Rents	
TOTAL Operation - Hyro	**2,129**
Maintenance	
(541) Maint Supervision and Engineering	
(542) Maint of Structures	
(543) Maint of Reservoirs, Dams & Waterways	
(544) Maint of Electric Plant	1,838
(545) Maint of Misc Hydraulic Plant	
TOTAL Maintenance - Hydo	**1,838**
TOTAL Power Production Expenses - Hydraulic Power	**3,967**
D. Other Power Generation	
Operation	
(546) Operation Supervision and Engineering	
(547) Fuel	
(548) Generation Expenses	
(549) Misc Other Power Generation Expenses	829
(550) Rents Gas Turbines	
(858) Trans By Others - Commodity	
TOTAL Operation - Other Power	**829**
Maintenance	
(551) Maint Supervision and Engineering	

FERC Income Stmt
2017 Control Budget
($000)

2017 Control Budget	Year 2017
Indiana Michigan Power	
(552) Maint of Structures	
(553) Maint of Generating and Electric Plant	
(554) Maint of Misc Other Power Gen Plant	
TOTAL Maintenance - Other Power	
TOTAL Power Production Expenses - Other Power	**829**
E. Other Power Supply Expenses	
(555) Purchased Power	413,197
(556) System Control & Load Dispatching	1,502
(557) Other Expenses	1,715
TOTAL OTher Power Supply Exp	**416,414**
Total Power Production Expenses	**1,072,489**
2. TRANSMISSION EXPENSES	
Operation	
(560) Operation Supervision and Engineering	3,102
(561) Load Displatching	8,284
(562) Station Expenses	
(563) Overhead Lines Expenses	
(564) Underground Lines Expenses	
(565) Transmission of Electricity by Others	84,938
(566) Misc Transmission Expenses	2,003
(567) Rents	
TOTAL Operation - Transm	**98,328**
Maintenance	
(568) Maint Supervision and Engineering	
(569) Maint of Structures	252
(570) Maint of Station Equipment	4,417
(571) Maint of Overhead Lines	6,237
(572) Maint of Underground Lines	
(573) Maint of Misc Transmission Plant	282
TOTAL Maintenance - Transm	**11,189**
TOTAL Transmission Expenses	**109,517**
3. REGIONAL MARKET EXPENSES	
Operation	
(575.7) Market Facilitation	4,812
TOTAL Operation - Regional Market	4,812
Maintenance	
(576.x) Maintenance of Facility	
TOTAL Maintenance - Regional Market	
TOTAL Regional Transmission and Market Expenses	4,812
4. DISTRIBUTION EXPENSES	
Operation	
(580) Operation Supervision and Engineering	4,775
(581) Load Dispatching	1,093
(582) Station Expenses	
(583) Overhead Lines Expenses	(385)
(584) Underground Lines Expenses	2,268
(585) Street Lighting & Signal System Expenses	

FERC Income Stmt
2017 Control Budget
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2017 Control Budget	Year 2017
Indiana Michigan Power	
(586) Meter Expenses	1,723
(587) Customer Installations Expenses	(2)
(588) Misc Distr Expenses	16,402
(589) Rents	1,620
TOTAL Operation - Distr	**27,492**
Maintenance	
(590) Maint Supervision and Engineering	30
(591) Maint of Structures	
(592) Maint of Station Equipment	1,511
(593) Maint of Overhead Lines	43,477
(594) Maint of Underground Lines	1,256
(595) Maint of Line Transformers	238
(596) Maint of Street Lighting & Signal Systems	(6)
(597) Maint of Meters	78
(598) Maint of Misc Distr Plant	193
TOTAL Maintenance - Distr	**46,777**
TOTAL Distribution Expenses	**74,269**
5. CUSTOMER ACCOUNTS EXPENSES	
Operation	
(901) Supervision	1,065
(902) Meter Reading Expenses	2,595
(903) Customer Records & Collection Expenses	11,691
(904) Uncollectible Accounts	
(905) Misc Customer Accounts Expenses	154
TOTAL Customer Accounts Expenses	**15,505**
6. CUSTOMER SERVICE & INFORMATION EXPENSES	
Operation	
(907) Customer Service Expenses	993
(908) Customer Assistance Expenses	35,192
(909) Informational and Instructional Expenses	36
(910) Misc Customer Service and Informational Expenses	
TOTAL Cust Service & Info Expenses	**36,221**
7. SALES EXPENSES	
Operation	
(911) Supervision	
(912) Demonstrating and Selling Expenses	490
(913) Advertising Expenses	
(916) Miscellaneous Sales Expenses	
TOTAL Sales Expenses	**490**
8. ADMINISTRATIVE & GENERAL EXPENSES	
Operation	
(920) Administrative and General Salaries	38,558
(921) Office Supplies and Expenses	5,482
(Less) (922) Admin Expense Transferred-Credit	3,865
(923) Outside Services Employed	10,606
(924) Property Insurance	3,528
(925) Injuries and Damages	7,646

FERC Income Stmt
2017 Control Budget
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2017 Control Budget	Year 2017
Indiana Michigan Power	
(926) Employee Pensions and Benefits	32,198
(927) Franchise Requirements	
(928) Regulatory Commission Expenses	13,970
(Less) (929) Duplicate Charges-Credit	
(930.1) General Advertising Expenses	74
(930.2) Misc General Expenses	4,005
(931) Rents	3,251
TOTAL Operation - A&G	**115,452**
Maintenance	
(935) Maintenance of General Plant	6,379
TOTAL Admin & General Expenses	121,832
TOTAL Electric Oper and Maint Expenses	1,435,134
Additional O&M Ledger Accounts:	
402.0000 Maintenace Exp - specific ledger acct	
Operation Expenses (401)	1,208,607
Maintenance Expenses (402)	226,527
Depreciation Expense (403.0 & 403.1002)	174,384
Deprec Exp for Asset Retirement (403.1)	1,620
Amort & Depl of Utility Plant (404-405)	27,056
Amort of Utility Plant Acq Adj (406)	
Regulatory Debits (407.3)	(3,330)
(Less) Regulatory Credits (407.4)	
Taxes Other Than Income (408.1)	97,454
Income Taxes - Federal (409.1)	(52,346)
Income Taxes - Other (409.1)	3,862
Provision for Deferred Income Taxes (410.1)	129,943
(Less) Prov for Deferred Income Taxes-CR (411.1)	
Investment Tax Credit Adj - Net (411.4)	(4,706)
(Less) Gains from Disp. of Utility Plant (411.6)	
Losses from Disp. of Utility Plant (411.7)	
(Less) Gains from Disposition of Allowances (411.8)	27
Losses from Disposition of Allowances (411.9)	
Accretion Expense (411.10)	9,326
TOTAL Utility Operating Expenses	1,818,369
Net Utility Operating Income	283,856
Other Income	
Rev Merchandising, Jobing & Contract Work (415)	
(Less) Costs & Exp of Merch, Jobing & Contract Work (416)	
Revenues from Nonutility Operations (417)	55,830
(Less) Expenses of Nonutility Operations (417.1)	45,008
Nonoperating Rental Income (418)	200
Equity in Earnings of Subsidiary Cos (418.1)	
Interest and Dividend Income (419)	1,500
Allowance for Other Funds Used During Constr (419.1)	16,001

FERC Income Stmt
2017 Control Budget
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2017 Control Budget	Year 2017
Indiana Michigan Power	
Misc Nonoperating Income (421)	8,996
Gain on Disposition of Property (421.1)	
TOTAL Other Income	**37,519**
Other Deductions	
Loss on Disposition of Property (421.2)	
Misc Amortization (425)	
Donations (426.1)	418
Life Insurance (426.2)	
Penalties (426.3)	
Exp for Certain Civic, Political & Related Activities (426.4)	1,206
Other Deductions (426.5)	10,564
TOTAL Other Deductions	**12,188**
Taxes Applicable to Other Income & Deductions	
Taxes Other Than Income Taxes (408.2)	1,513
Income Taxes - Federal (409.2)	2,736
Income Taxes - Other (409.2)	446
Provision for Deferred Inc. Taxes (410.2)	
(Less) Provision for Deferred Inc Taxes-Cr. (411.2)	
Investment Tax Credit Adj-Net (411.5)	
TOTAL Taxes on Other Income and Deductions	**4,695**
Net Other Income and Deductions	**20,636**
Interest Charges	
Interest on Long-Term Debt (427)	102,840
Amort of Debt Disc. & Expense (428)	1,479
Amort of Loss on Reacquired Debt (428.1)	1,012
(Less) Amort of Premium on Debt-Credit (429)	
(Less) Amort of Gain on Reacquired Debt-Credit (429.1)	
Interest on Debt to Assoc Cos (430)	2,094
Other Interest Expense (431)	12,708
(Less) Allowance for Borrowed Funds Used During Constr-Cr. (432)	8,158
Net Interest Charges	**111,976**
Income Before Extraordinary Items	**192,516**
Extraordinary Items	
Extraordinary Income (434)	
(Less) Extraordinary Deductions (435)	
Net Extraordinary Items	
Income Taxes-Federal & Other (409.3)	
Extraordinary Items After Taxes	
Net Income	192,516
(Less) Preferred Dividends	
Balance For Common	**192,516**
Operation Expense, excld Fuel & Purchased Power	516,220
Maintenance Expense	226,527

FERC Income Stmt
2018 Control Budget
($000)

2018 Control Budget	Year 2018
Indiana Michigan Power	
UTILITY OPERATING INCOME	
(440) Residential Sales	643,207
(442) Commercial Sales	474,425
(442) Industrial Sales	578,794
(444) Public Street & Highway Lighting	7,914
(445) Other Sales to Public Authorities	
Unclassified Goal-Seek Revenues	
TOTAL Sales to Ultimate Customers	**1,704,341**
(447) Sales for Resale	478,253
TOTAL Sales of Electricity	**2,182,594**
Less: (449.1) Provision for Rate Refunds	
TOTAL Revenues Net of Prov. for Refunds	**2,182,594**
Other Operating Revenues	
(450) Forfeited Discounts	5,129
(451) Misc. Service Revenues	5,003
(454) Rent from Electric Property	8,090
(456) Other Electric Revenues	25,432
(457) Services Rendered to Associated Cos.	
(458) Services Rendered to Non-Associated Cos.	
Total Other Operating Revenues	**43,654**
Total Electric Operating Revenues (400)	**2,226,248**
OPERATING EXPENSES	
Operation & Maintenance Details	
1. POWER PRODUCTION EXPENSES	
A. Steam Power Generation	
Operation	
(500) Operation Supervision & Engineering	5,107
(501) Fuel	178,995
(502) Steam Expense	17,447
(505) Electric Expense	143
(506) Misc Steam Power Expense	7,893
(507) Rents	70,159
(508) IPP Admin	
(509) Allowances	1,506
TOTAL Operation - Steam	**281,250**
Maintenance	
(510) Maint Supervision and Engineering	2,134
(511) Maint of Structures	
(512) Maint of Boiler Plant	16,669
(513) Maint of Electric Plant	1,570
(514) Maint of Misc Steam Plant	79
(515) Maint of Steam Production Plant	
TOTAL Maintenance - Steam	**20,451**

FERC Income Stmt
2018 Control Budget
($000)

2018 Control Budget	Year 2018
Indiana Michigan Power	
TOTAL Power Production Expense - Steam Power	**301,701**
B. Nuclear Power Generation	
Operation	
(517) Operation Supervision and Engineering	11,007
(518) Fuel	110,633
(519) Coolants and Water	8,262
(520) Steam Expense	8,975
(523) Electric Expenses	4,337
(524) Misc Nuclear Power Expenses	79,790
(525) Rents	
TOTAL Operation - Nuclear	**223,002**
Maintenance	
(528) Maint Supervision and Engineering	4,146
(529) Maint of Structures	2,088
(530) Maint of Reactor Plant Equipment	105,834
(531) Maint of Electric Plant	6,101
(532) Maint of Misc Nuclear Plant	41,186
TOTAL Maintenance - Nuclear	**159,355**
TOTAL Power Production Expense - Nuclear Power	**382,357**
C. Hydraulic Power Generation	
Operation	
(535) Operation Supervision and Engineering	
(536) Water for Power	
(537) Hydraulic Expenses	
(538) Electric Expenses	
(539) Misc Hydraulic Power Generation Expenses	1,249
(540) Rents	
TOTAL Operation - Hyro	**1,249**
Maintenance	
(541) Maint Supervision and Engineering	
(542) Maint of Structures	
(543) Maint of Reservoirs, Dams & Waterways	
(544) Maint of Electric Plant	2,310
(545) Maint of Misc Hydraulic Plant	
TOTAL Maintenance - Hydo	**2,310**
TOTAL Power Production Expenses - Hydraulic Power	**3,559**
D. Other Power Generation	
Operation	
(546) Operation Supervision and Engineering	
(547) Fuel	
(548) Generation Expenses	
(549) Misc Other Power Generation Expenses	1,001
(550) Rents Gas Turbines	
(858) Trans By Others - Commodity	
TOTAL Operation - Other Power	**1,001**
Maintenance	
(551) Maint Supervision and Engineering	

FERC Income Stmt
2018 Control Budget
($000)

2018 Control Budget	Year 2018
Indiana Michigan Power	
(552) Maint of Structures	
(553) Maint of Generating and Electric Plant	
(554) Maint of Misc Other Power Gen Plant	
TOTAL Maintenance - Other Power	
TOTAL Power Production Expenses - Other Power	**1,001**
E. Other Power Supply Expenses	
(555) Purchased Power	419,733
(556) System Control & Load Dispatching	1,257
(557) Other Expenses	1,577
TOTAL OTher Power Supply Exp	**422,566**
Total Power Production Expenses	**1,111,185**
2. TRANSMISSION EXPENSES	
Operation	
(560) Operation Supervision and Engineering	5,955
(561) Load Displatching	8,166
(562) Station Expenses	
(563) Overhead Lines Expenses	
(564) Underground Lines Expenses	
(565) Transmission of Electricity by Others	122,121
(566) Misc Transmission Expenses	2,134
(567) Rents	
TOTAL Operation - Transm	**138,376**
Maintenance	
(568) Maint Supervision and Engineering	
(569) Maint of Structures	239
(570) Maint of Station Equipment	4,267
(571) Maint of Overhead Lines	8,626
(572) Maint of Underground Lines	
(573) Maint of Misc Transmission Plant	23
TOTAL Maintenance - Transm	**13,156**
TOTAL Transmission Expenses	**151,532**
3. REGIONAL MARKET EXPENSES	
Operation	
(575.7) Market Facilitation	4,846
TOTAL Operation - Regional Market	4,846
Maintenance	
(576.x) Maintenance of Facility	
TOTAL Maintenance - Regional Market	
TOTAL Regional Transmission and Market Expenses	4,846
4. DISTRIBUTION EXPENSES	
Operation	
(580) Operation Supervision and Engineering	4,686
(581) Load Dispatching	997
(582) Station Expenses	
(583) Overhead Lines Expenses	3,379
(584) Underground Lines Expenses	2,370
(585) Street Lighting & Signal System Expenses	

FERC Income Stmt
2018 Control Budget
($000)

2018 Control Budget	Year 2018
Indiana Michigan Power	
(586) Meter Expenses	1,407
(587) Customer Installations Expenses	171
(588) Misc Distr Expenses	16,116
(589) Rents	1,620
TOTAL Operation - Distr	**30,746**
Maintenance	
(590) Maint Supervision and Engineering	12
(591) Maint of Structures	
(592) Maint of Station Equipment	1,693
(593) Maint of Overhead Lines	43,085
(594) Maint of Underground Lines	1,433
(595) Maint of Line Transformers	
(596) Maint of Street Lighting & Signal Systems	(6)
(597) Maint of Meters	81
(598) Maint of Misc Distr Plant	202
TOTAL Maintenance - Distr	**46,499**
TOTAL Distribution Expenses	**77,245**
5. CUSTOMER ACCOUNTS EXPENSES	
Operation	
(901) Supervision	1,079
(902) Meter Reading Expenses	2,954
(903) Customer Records & Collection Expenses	11,347
(904) Uncollectible Accounts	
(905) Misc Customer Accounts Expenses	3,960
TOTAL Customer Accounts Expenses	**19,340**
6. CUSTOMER SERVICE & INFORMATION EXPENSES	
Operation	
(907) Customer Service Expenses	1,202
(908) Customer Assistance Expenses	29,178
(909) Informational and Instructional Expenses	36
(910) Misc Customer Service and Informational Expenses	
TOTAL Cust Service & Info Expenses	**30,417**
7. SALES EXPENSES	
Operation	
(911) Supervision	
(912) Demonstrating and Selling Expenses	396
(913) Advertising Expenses	
(916) Miscellaneous Sales Expenses	
TOTAL Sales Expenses	**396**
8. ADMINISTRATIVE & GENERAL EXPENSES	
Operation	
(920) Administrative and General Salaries	42,986
(921) Office Supplies and Expenses	4,792
(Less) (922) Admin Expense Transferred-Credit	3,221
(923) Outside Services Employed	3,704
(924) Property Insurance	5,694
(925) Injuries and Damages	7,729

FERC Income Stmt
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2018 Control Budget	Year 2018
Indiana Michigan Power	
(926) Employee Pensions and Benefits	24,089
(927) Franchise Requirements	
(928) Regulatory Commission Expenses	12,470
(Less) (929) Duplicate Charges-Credit	
(930.1) General Advertising Expenses	75
(930.2) Misc General Expenses	3,894
(931) Rents	3,224
TOTAL Operation - A&G	**105,438**
Maintenance	
(935) Maintenance of General Plant	5,619
TOTAL Admin & General Expenses	111,058
TOTAL Electric Oper and Maint Expenses	1,506,017
Additional O&M Ledger Accounts:	
402.0000 Maintenace Exp - specific ledger acct	
Operation Expenses (401)	1,258,627
Maintenance Expenses (402)	247,390
Depreciation Expense (403.0 & 403.1002)	252,165
Deprec Exp for Asset Retirement (403.1)	1,813
Amort & Depl of Utility Plant (404-405)	34,136
Amort of Utility Plant Acq Adj (406)	
Regulatory Debits (407.3)	(4,300)
(Less) Regulatory Credits (407.4)	
Taxes Other Than Income (408.1)	103,796
Income Taxes - Federal (409.1)	20,601
Income Taxes - Other (409.1)	(2,996)
Provision for Deferred Income Taxes (410.1)	29,277
(Less) Prov for Deferred Income Taxes-CR (411.1)	23,080
Investment Tax Credit Adj - Net (411.4)	(5,214)
(Less) Gains from Disp. of Utility Plant (411.6)	
Losses from Disp. of Utility Plant (411.7)	
(Less) Gains from Disposition of Allowances (411.8)	42
Losses from Disposition of Allowances (411.9)	
Accretion Expense (411.10)	7,782
TOTAL Utility Operating Expenses	1,919,956
Net Utility Operating Income	306,292
Other Income	
Rev Merchandising, Jobing & Contract Work (415)	
(Less) Costs & Exp of Merch, Jobing & Contract Work (416)	
Revenues from Nonutility Operations (417)	48,037
(Less) Expenses of Nonutility Operations (417.1)	44,347
Nonoperating Rental Income (418)	154
Equity in Earnings of Subsidiary Cos (418.1)	
Interest and Dividend Income (419)	1,493
Allowance for Other Funds Used During Constr (419.1)	10,050

FERC Income Stmt
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2018 Control Budget	Year 2018
Indiana Michigan Power	
Misc Nonoperating Income (421)	7,365
Gain on Disposition of Property (421.1)	
TOTAL Other Income	**22,752**
Other Deductions	
Loss on Disposition of Property (421.2)	
Misc Amortization (425)	
Donations (426.1)	1,418
Life Insurance (426.2)	
Penalties (426.3)	
Exp for Certain Civic, Political & Related Activities (426.4)	1,016
Other Deductions (426.5)	9,557
TOTAL Other Deductions	**11,992**
Taxes Applicable to Other Income & Deductions	
Taxes Other Than Income Taxes (408.2)	3,280
Income Taxes - Federal (409.2)	(540)
Income Taxes - Other (409.2)	(144)
Provision for Deferred Inc. Taxes (410.2)	
(Less) Provision for Deferred Inc Taxes-Cr. (411.2)	
Investment Tax Credit Adj-Net (411.5)	
TOTAL Taxes on Other Income and Deductions	**2,596**
Net Other Income and Deductions	**8,164**
Interest Charges	
Interest on Long-Term Debt (427)	122,680
Amort of Debt Disc. & Expense (428)	2,023
Amort of Loss on Reacquired Debt (428.1)	1,468
(Less) Amort of Premium on Debt-Credit (429)	
(Less) Amort of Gain on Reacquired Debt-Credit (429.1)	
Interest on Debt to Assoc Cos (430)	1,742
Other Interest Expense (431)	9,768
(Less) Allowance for Borrowed Funds Used During Constr-Cr. (432)	6,538
Net Interest Charges	**131,143**
Income Before Extraordinary Items	**183,313**
Extraordinary Items	
Extraordinary Income (434)	
(Less) Extraordinary Deductions (435)	
Net Extraordinary Items	
Income Taxes-Federal & Other (409.3)	
Extraordinary Items After Taxes	
Net Income	183,313
(Less) Preferred Dividends	
Balance For Common	**183,313**
Operation Expense, excld Fuel & Purchased Power	544,420
Maintenance Expense	247,390

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2019 Control Budget	Year 2019
Indiana Michigan Power	
UTILITY OPERATING INCOME	
(440) Residential Sales	732,853
(442) Commercial Sales	512,377
(442) Industrial Sales	584,008
(444) Public Street & Highway Lighting	8,978
(445) Other Sales to Public Authorities	
Unclassified Goal-Seek Revenues	
TOTAL Sales to Ultimate Customers	**1,838,217**
(447) Sales for Resale	448,699
TOTAL Sales of Electricity	**2,286,916**
Less: (449.1) Provision for Rate Refunds	
TOTAL Revenues Net of Prov. for Refunds	**2,286,916**
Other Operating Revenues	
(450) Forfeited Discounts	5,202
(451) Misc. Service Revenues	4,828
(454) Rent from Electric Property	8,651
(456) Other Electric Revenues	29,985
(457) Services Rendered to Associated Cos.	
(458) Services Rendered to Non-Associated Cos.	
Total Other Operating Revenues	**48,666**
Total Electric Operating Revenues (400)	**2,335,581**
OPERATING EXPENSES	
Operation & Maintenance Details	
1. POWER PRODUCTION EXPENSES	
A. Steam Power Generation	
Operation	
(500) Operation Supervision & Engineering	4,714
(501) Fuel	157,720
(502) Steam Expense	13,687
(505) Electric Expense	
(506) Misc Steam Power Expense	7,861
(507) Rents	70,158
(508) IPP Admin ???	
(509) Allowances	1,388
TOTAL Operation - Steam	**255,528**
Maintenance	
(510) Maint Supervision and Engineering	2,839
(511) Maint of Structures	
(512) Maint of Boiler Plant	13,037
(513) Maint of Electric Plant	814
(514) Maint of Misc Steam Plant	
(515) Maint of Steam Production Plant	

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TOTAL Maintenance - Steam	**16,690**
TOTAL Power Production Expense - Steam Power	**272,218**
B. Nuclear Power Generation	
Operation	
(517) Operation Supervision and Engineering	10,806
(518) Fuel	89,955
(519) Coolants and Water	8,678
(520) Steam Expense	7,930
(523) Electric Expenses	4,470
(524) Misc Nuclear Power Expenses	79,003
(525) Rents	
TOTAL Operation - Nuclear	**200,843**
Maintenance	
(528) Maint Supervision and Engineering	4,961
(529) Maint of Structures	2,129
(530) Maint of Reactor Plant Equipment	92,970
(531) Maint of Electric Plant	7,504
(532) Maint of Misc Nuclear Plant	38,487
TOTAL Maintenance - Nuclear	**146,051**
TOTAL Power Production Expense - Nuclear Power	**346,894**
C. Hydraulic Power Generation	
Operation	
(535) Operation Supervision and Engineering	
(536) Water for Power	
(537) Hydraulic Expenses	
(538) Electric Expenses	
(539) Misc Hydraulic Power Generation Expenses	1,856
(540) Rents	
TOTAL Operation - Hyro	**1,856**
Maintenance	
(541) Maint Supervision and Engineering	
(542) Maint of Structures	
(543) Maint of Reservoirs, Dams & Waterways	
(544) Maint of Electric Plant	1,465
(545) Maint of Misc Hydraulic Plant	
TOTAL Maintenance - Hydo	**1,465**
TOTAL Power Production Expenses - Hydraulic Power	**3,322**
D. Other Power Generation	
Operation	
(546) Operation Supervision and Engineering	
(547) Fuel	
(548) Generation Expenses	
(549) Misc Other Power Generation Expenses	228
(550) Rents Gas Turbines	
(858) Trans By Others - Commodity	
TOTAL Operation - Other Power	**228**
Maintenance	
(551) Maint Supervision and Engineering	
(552) Maint of Structures	
(553) Maint of Generating and Electric Plant	
(554) Maint of Misc Other Power Gen Plant	

FERC Income Stmt
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TOTAL Maintenance - Other Power	
TOTAL Power Production Expenses - Other Power	**228**
E. Other Power Supply Expenses	
(555) Purchased Power	476,473
(556) System Control & Load Dispatching	1,329
(557) Other Expenses	1,526
TOTAL OTher Power Supply Exp	**479,328**
Total Power Production Expenses	**1,101,990**
2. TRANSMISSION EXPENSES	
Operation	
(560) Operation Supervision and Engineering	4,428
(561) Load Displatching	7,877
(562) Station Expenses	
(563) Overhead Lines Expenses	
(564) Underground Lines Expenses	
(565) Transmission of Electricity by Others	127,144
(566) Misc Transmission Expenses	2,307
(567) Rents	
TOTAL Operation - Transm	**141,756**
Maintenance	
(568) Maint Supervision and Engineering	
(569) Maint of Structures	223
(570) Maint of Station Equipment	4,664
(571) Maint of Overhead Lines	9,255
(572) Maint of Underground Lines	
(573) Maint of Misc Transmission Plant	
TOTAL Maintenance - Transm	**14,142**
TOTAL Transmission Expenses	**155,898**
3. REGIONAL MARKET EXPENSES	
Operation	
(575.7) Market Facilitation	5,157
TOTAL Operation - Regional Market	5,157
Maintenance	
(576.x) Maintenance of Facility	
TOTAL Maintenance - Regional Market	
TOTAL Regional Transmission and Market Expenses	5,157
4. DISTRIBUTION EXPENSES	
Operation	
(580) Operation Supervision and Engineering	4,038
(581) Load Dispatching	959
(582) Station Expenses	
(583) Overhead Lines Expenses	1,152
(584) Underground Lines Expenses	2,157
(585) Street Lighting & Signal System Expenses	
(586) Meter Expenses	3,091
(587) Customer Installations Expenses	195
(588) Misc Distr Expenses	14,418
(589) Rents	1,620
TOTAL Operation - Distr	**27,630**
Maintenance	
(590) Maint Supervision and Engineering	

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(591) Maint of Structures	
(592) Maint of Station Equipment	1
(593) Maint of Overhead Lines	38,970
(594) Maint of Underground Lines	1,192
(595) Maint of Line Transformers	
(596) Maint of Street Lighting & Signal Systems	(7)
(597) Maint of Meters	84
(598) Maint of Misc Distr Plant	204
TOTAL Maintenance - Distr	**40,445**
TOTAL Distribution Expenses	**68,075**
5. CUSTOMER ACCOUNTS EXPENSES	
Operation	
(901) Supervision	1,079
(902) Meter Reading Expenses	1,202
(903) Customer Records & Collection Expenses	10,579
(904) Uncollectible Accounts	
(905) Misc Customer Accounts Expenses	3,941
TOTAL Customer Accounts Expenses	**16,801**
6. CUSTOMER SERVICE & INFORMATION EXPENSES	
Operation	
(907) Customer Service Expenses	1,299
(908) Customer Assistance Expenses	32,005
(909) Informational and Instructional Expenses	37
(910) Misc Customer Service and Informational Expenses	
TOTAL Cust Service & Info Expenses	**33,341**
7. SALES EXPENSES	
Operation	
(911) Supervision	
(912) Demonstrating and Selling Expenses	370
(913) Advertising Expenses	
(916) Miscellaneous Sales Expenses	
TOTAL Sales Expenses	**370**
8. ADMINISTRATIVE & GENERAL EXPENSES	
Operation	
(920) Administrative and General Salaries	45,908
(921) Office Supplies and Expenses	4,245
(Less) (922) Admin Expense Transferred-Credit	3,860
(923) Outside Services Employed	4,808
(924) Property Insurance	3,612
(925) Injuries and Damages	8,845
(926) Employee Pensions and Benefits	17,076
(927) Franchise Requirements	
(928) Regulatory Commission Expenses	12,067
(Less) (929) Duplicate Charges-Credit	
(930.1) General Advertising Expenses	76
(930.2) Misc General Expenses	3,642
(931) Rents	3,161
TOTAL Operation - A&G	**99,581**
Maintenance	
(935) Maintenance of General Plant	4,896
TOTAL Admin & General Expenses	104,477

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TOTAL Electric Oper and Maint Expenses	1,486,109
Additional O&M Ledger Accounts:	
402.0000 Maintenace Exp - specific ledger acct	
Operation Expenses (401)	1,262,419
Maintenance Expenses (402)	223,690
Depreciation Expense (403.0 & 403.1002)	322,246
Deprec Exp for Asset Retirement (403.1)	1,819
Amort & Depl of Utility Plant (404-405)	47,253
Amort of Utility Plant Acq Adj (406)	
Regulatory Debits (407.3)	3,797
(Less) Regulatory Credits (407.4)	
Taxes Other Than Income (408.1)	107,245
Income Taxes - Federal (409.1)	44,120
Income Taxes - Other (409.1)	6,774
Provision for Deferred Income Taxes (410.1)	(1,239)
(Less) Prov for Deferred Income Taxes-CR (411.1)	38,082
Investment Tax Credit Adj - Net (411.4)	(5,214)
(Less) Gains from Disp. of Utility Plant (411.6)	
Losses from Disp. of Utility Plant (411.7)	
(Less) Gains from Disposition of Allowances (411.8)	2
Losses from Disposition of Allowances (411.9)	
Accretion Expense (411.10)	5,809
TOTAL Utility Operating Expenses	1,980,635
Net Utility Operating Income	354,946
Other Income	
Rev Merchandising, Jobing & Contract Work (415)	
(Less) Costs & Exp of Merch, Jobing & Contract Work (416)	
Revenues from Nonutility Operations (417)	54,198
(Less) Expenses of Nonutility Operations (417.1)	50,829
Nonoperating Rental Income (418)	130
Equity in Earnings of Subsidiary Cos (418.1)	
Interest and Dividend Income (419)	3,431
Allowance for Other Funds Used During Constr (419.1)	21,362
Misc Nonoperating Income (421)	(2,453)
Gain on Disposition of Property (421.1)	150
TOTAL Other Income	**25,988**
Other Deductions	
Loss on Disposition of Property (421.2)	
Misc Amortization (425)	
Donations (426.1)	1,423
Life Insurance (426.2)	
Penalties (426.3)	
Exp for Certain Civic, Political & Related Activities (426.4)	879
Other Deductions (426.5)	10,692
TOTAL Other Deductions	**12,994**
Taxes Applicable to Other Income & Deductions	
Taxes Other Than Income Taxes (408.2)	2,595
Income Taxes - Federal (409.2)	(2,302)

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Income Taxes - Other (409.2)	(597)
Provision for Deferred Inc. Taxes (410.2)	
(Less) Provision for Deferred Inc Taxes-Cr. (411.2)	
Investment Tax Credit Adj-Net (411.5)	
TOTAL Taxes on Other Income and Deductions	**(304)**
Net Other Income and Deductions	**13,298**
Interest Charges	
Interest on Long-Term Debt (427)	126,645
Amort of Debt Disc. & Expense (428)	2,192
Amort of Loss on Reacquired Debt (428.1)	1,499
(Less) Amort of Premium on Debt-Credit (429)	
(Less) Amort of Gain on Reacquired Debt-Credit (429.1)	
Interest on Debt to Assoc Cos (430)	1,749
Other Interest Expense (431)	10,712
(Less) Allowance for Borrowed Funds Used During Constr-Cr. (432)	11,976
Net Interest Charges	**130,820**
Income Before Extraordinary Items	**237,424**
Extraordinary Items	
Extraordinary Income (434)	
(Less) Extraordinary Deductions (435)	
Net Extraordinary Items	
Income Taxes-Federal & Other (409.3)	
Extraordinary Items After Taxes	
Net Income	237,424
(Less) Preferred Dividends	
Balance For Common	**237,424**
Operation Expense, excld Fuel & Purchased Power	533,114
Maintenance Expense	223,690

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2020 Control Budget	Year 2020
Indiana Michigan Power	
UTILITY OPERATING INCOME	
(440) Residential Sales	786,132
(442) Commercial Sales	527,926
(442) Industrial Sales	573,900
(444) Public Street & Highway Lighting	7,942
(445) Other Sales to Public Authorities	
Unclassified Goal-Seek Revenues	
TOTAL Sales to Ultimate Customers	**1,895,900**
(447) Sales for Resale	434,105
TOTAL Sales of Electricity	**2,330,005**
Less: (449.1) Provision for Rate Refunds	
TOTAL Revenues Net of Prov. for Refunds	**2,330,005**
Other Operating Revenues	
(450) Forfeited Discounts	8,661
(451) Misc. Service Revenues	7,198
(454) Rent from Electric Property	7,982
(456) Other Electric Revenues	35,101
(457) Services Rendered to Associated Cos.	
(458) Services Rendered to Non-Associated Cos.	
Total Other Operating Revenues	**58,942**
Total Electric Operating Revenues (400)	**2,388,947**
OPERATING EXPENSES	
Operation & Maintenance Details	
1. POWER PRODUCTION EXPENSES	
A. Steam Power Generation	
Operation	
(500) Operation Supervision & Engineering	5,857
(501) Fuel	148,776
(502) Steam Expense	20,179
(505) Electric Expense	
(506) Misc Steam Power Expense	7,287
(507) Rents	69,214
(508) IPP Admin ???	
(509) Allowances	986
TOTAL Operation - Steam	**252,299**
Maintenance	
(510) Maint Supervision and Engineering	5,275
(511) Maint of Structures	
(512) Maint of Boiler Plant	6,959
(513) Maint of Electric Plant	(208)
(514) Maint of Misc Steam Plant	
(515) Maint of Steam Production Plant	

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TOTAL Maintenance - Steam	**12,025**
TOTAL Power Production Expense - Steam Power	**264,325**
B. Nuclear Power Generation	
Operation	
(517) Operation Supervision and Engineering	13,260
(518) Fuel	91,051
(519) Coolants and Water	8,732
(520) Steam Expense	4,434
(523) Electric Expenses	4,765
(524) Misc Nuclear Power Expenses	91,809
(525) Rents	
TOTAL Operation - Nuclear	**214,052**
Maintenance	
(528) Maint Supervision and Engineering	4,361
(529) Maint of Structures	2,526
(530) Maint of Reactor Plant Equipment	88,561
(531) Maint of Electric Plant	7,161
(532) Maint of Misc Nuclear Plant	22,313
TOTAL Maintenance - Nuclear	**124,922**
TOTAL Power Production Expense - Nuclear Power	**338,973**
C. Hydraulic Power Generation	
Operation	
(535) Operation Supervision and Engineering	
(536) Water for Power	
(537) Hydraulic Expenses	
(538) Electric Expenses	
(539) Misc Hydraulic Power Generation Expenses	1,945
(540) Rents	
TOTAL Operation - Hyro	**1,945**
Maintenance	
(541) Maint Supervision and Engineering	
(542) Maint of Structures	
(543) Maint of Reservoirs, Dams & Waterways	
(544) Maint of Electric Plant	2,218
(545) Maint of Misc Hydraulic Plant	
TOTAL Maintenance - Hydo	**2,218**
TOTAL Power Production Expenses - Hydraulic Power	**4,163**
D. Other Power Generation	
Operation	
(546) Operation Supervision and Engineering	
(547) Fuel	
(548) Generation Expenses	
(549) Misc Other Power Generation Expenses	298
(550) Rents Gas Turbines	
(858) Trans By Others - Commodity	
TOTAL Operation - Other Power	**298**
Maintenance	
(551) Maint Supervision and Engineering	
(552) Maint of Structures	
(553) Maint of Generating and Electric Plant	
(554) Maint of Misc Other Power Gen Plant	

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TOTAL Maintenance - Other Power	
TOTAL Power Production Expenses - Other Power	**298**
E. Other Power Supply Expenses	
(555) Purchased Power	440,435
(556) System Control & Load Dispatching	423
(557) Other Expenses	967
TOTAL OTher Power Supply Exp	**441,826**
Total Power Production Expenses	**1,049,585**
2. TRANSMISSION EXPENSES	
Operation	
(560) Operation Supervision and Engineering	4,156
(561) Load Displatching	8,073
(562) Station Expenses	
(563) Overhead Lines Expenses	
(564) Underground Lines Expenses	
(565) Transmission of Electricity by Others	160,706
(566) Misc Transmission Expenses	1,751
(567) Rents	
TOTAL Operation - Transm	**174,686**
Maintenance	
(568) Maint Supervision and Engineering	
(569) Maint of Structures	167
(570) Maint of Station Equipment	3,350
(571) Maint of Overhead Lines	8,010
(572) Maint of Underground Lines	
(573) Maint of Misc Transmission Plant	
TOTAL Maintenance - Transm	**11,528**
TOTAL Transmission Expenses	**186,213**
3. REGIONAL MARKET EXPENSES	
Operation	
(575.7) Market Facilitation	5,143
TOTAL Operation - Regional Market	5,143
Maintenance	
(576.x) Maintenance of Facility	
TOTAL Maintenance - Regional Market	
TOTAL Regional Transmission and Market Expenses	5,143
4. DISTRIBUTION EXPENSES	
Operation	
(580) Operation Supervision and Engineering	4,804
(581) Load Dispatching	1,013
(582) Station Expenses	
(583) Overhead Lines Expenses	2,161
(584) Underground Lines Expenses	2,116
(585) Street Lighting & Signal System Expenses	
(586) Meter Expenses	3,467
(587) Customer Installations Expenses	231
(588) Misc Distr Expenses	18,443
(589) Rents	1,720
TOTAL Operation - Distr	**33,955**
Maintenance	
(590) Maint Supervision and Engineering	

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(591) Maint of Structures	
(592) Maint of Station Equipment	2,238
(593) Maint of Overhead Lines	42,124
(594) Maint of Underground Lines	1,186
(595) Maint of Line Transformers	
(596) Maint of Street Lighting & Signal Systems	(7)
(597) Maint of Meters	110
(598) Maint of Misc Distr Plant	217
TOTAL Maintenance - Distr	**45,869**
TOTAL Distribution Expenses	**79,824**
5. CUSTOMER ACCOUNTS EXPENSES	
Operation	
(901) Supervision	1,272
(902) Meter Reading Expenses	1,208
(903) Customer Records & Collection Expenses	11,972
(904) Uncollectible Accounts	
(905) Misc Customer Accounts Expenses	3,796
TOTAL Customer Accounts Expenses	**18,248**
6. CUSTOMER SERVICE & INFORMATION EXPENSES	
Operation	
(907) Customer Service Expenses	1,641
(908) Customer Assistance Expenses	33,739
(909) Informational and Instructional Expenses	
(910) Misc Customer Service and Informational Expenses	
TOTAL Cust Service & Info Expenses	**35,381**
7. SALES EXPENSES	
Operation	
(911) Supervision	
(912) Demonstrating and Selling Expenses	418
(913) Advertising Expenses	
(916) Miscellaneous Sales Expenses	
TOTAL Sales Expenses	**418**
8. ADMINISTRATIVE & GENERAL EXPENSES	
Operation	
(920) Administrative and General Salaries	51,206
(921) Office Supplies and Expenses	2,368
(Less) (922) Admin Expense Transferred-Credit	4,411
(923) Outside Services Employed	11,254
(924) Property Insurance	(5,515)
(925) Injuries and Damages	8,266
(926) Employee Pensions and Benefits	22,388
(927) Franchise Requirements	
(928) Regulatory Commission Expenses	11,571
(Less) (929) Duplicate Charges-Credit	
(930.1) General Advertising Expenses	77
(930.2) Misc General Expenses	5,322
(931) Rents	4,135
TOTAL Operation - A&G	**106,661**
Maintenance	
(935) Maintenance of General Plant	5,028
TOTAL Admin & General Expenses	111,690

FERC Income Stmt
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TOTAL Electric Oper and Maint Expenses	1,486,501
Additional O&M Ledger Accounts:	
Operation Expenses (401)	1,284,911
Maintenance Expenses (402)	201,590
Depreciation Expense (403.0 & 403.1002)	362,989
Deprec Exp for Asset Retirement (403.1)	2,179
Amort & Depl of Utility Plant (404-405)	45,142
Amort of Utility Plant Acq Adj (406)	
Regulatory Debits (407.3)	
(Less) Regulatory Credits (407.4)	
Taxes Other Than Income (408.1)	110,183
Income Taxes - Federal (409.1)	55,604
Income Taxes - Other (409.1)	10,826
Provision for Deferred Income Taxes (410.1)	(15,003)
(Less) Prov for Deferred Income Taxes-CR (411.1)	40,220
Investment Tax Credit Adj - Net (411.4)	(4,542)
(Less) Gains from Disp. of Utility Plant (411.6)	
Losses from Disp. of Utility Plant (411.7)	
(Less) Gains from Disposition of Allowances (411.8)	90
Losses from Disposition of Allowances (411.9)	
Accretion Expense (411.10)	6,852
TOTAL Utility Operating Expenses	2,020,421
Net Utility Operating Income	368,526
Other Income	
Rev Merchandising, Jobing & Contract Work (415)	
(Less) Costs & Exp of Merch, Jobing & Contract Work (416	
Revenues from Nonutility Operations (417)	55,282
(Less) Expenses of Nonutility Operations (417.1)	52,670
Nonoperating Rental Income (418)	240
Equity in Earnings of Subsidiary Cos (418.1)	
Interest and Dividend Income (419)	2,146
Allowance for Other Funds Used During Constr (419.1)	12,032
Misc Nonoperating Income (421)	(2,091)
Gain on Disposition of Property (421.1)	0
TOTAL Other Income	**14,939**
Other Deductions	
Loss on Disposition of Property (421.2)	
Misc Amortization (425)	
Donations (426.1)	1,164
Life Insurance (426.2)	
Penalties (426.3)	
Exp for Certain Civic, Political & Related Activities (426.	910
Other Deductions (426.5)	11,823
TOTAL Other Deductions	**13,897**
Taxes Applicable to Other Income & Deductions	
Taxes Other Than Income Taxes (408.2)	2,640
Income Taxes - Federal (409.2)	(2,862)
Income Taxes - Other (409.2)	(697)

FERC Income Stmt
2020 Control Budget
($000)

Provision for Deferred Inc. Taxes (410.2)	
(Less) Provision for Deferred Inc Taxes-Cr. (411.2)	
Investment Tax Credit Adj-Net (411.5)	
TOTAL Taxes on Other Income and Deductions	**(920)**
Net Other Income and Deductions	**1,962**
Interest Charges	
Interest on Long-Term Debt (427)	119,303
Amort of Debt Disc. & Expense (428)	2,069
Amort of Loss on Reacquired Debt (428.1)	1,675
(Less) Amort of Premium on Debt-Credit (429)	
(Less) Amort of Gain on Reacquired Debt-Credit (429.1)	
Interest on Debt to Assoc Cos (430)	1,569
Other Interest Expense (431)	10,886
(Less) Allowance for Borrowed Funds Used During Constr-	7,466
Net Interest Charges	**128,036**
Income Before Extraordinary Items	**242,452**
Extraordinary Items	
Extraordinary Income (434)	
(Less) Extraordinary Deductions (435)	
Net Extraordinary Items	
Income Taxes-Federal & Other (409.3)	
Extraordinary Items After Taxes	
Net Income	242,452
(Less) Preferred Dividends	
Balance For Common	**242,452**
Operation Expense, excld Fuel & Purchased Power	599,505
Maintenance Expense	201,590

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 25
IURC CAUSE NO. 45576

DATA REQUEST NO OUCC 25-07

REQUEST

Pension and OPEB Prepayments: Please provide an analysis of the prepaid OPEB asset by year beginning with the adoption of FAS 106 and continuing through 2022, showing the beginning balance, the amount of each item increasing the prepaid asset each year, the amount of each item decreasing the prepaid asset each year, and the prepayment ending balance each year. Please provide the response to this request in Excel compatible format with all formulas intact and fully functional.

RESPONSE

Please see 45576_IndMich_OUCC 25-07 Attachment 1_09242021.xlsx for I&M Total Company prepaid OPEB asset reconciliations for the years 2014 through 2022. Please note that the year-end December 31, 2022 forecasted prepaid OPEB asset balance differs from the December 31, 2022 balance included in the Company's Forecasted Test Year in this case due to an updated annualization of 2021 OPEB expense (credit) as provided by the Company's third party actuary, Willis Towers Watson.

Indiana Michigan Power Company
FAS 106 Prepaid OPEB History
Amounts Presented on an I&M Total Company Basis

Year	Beginning Balance	Establishment of Prepaid	Transfers	Expense (Credit) (Net Periodic Postretirement Benefit Cost)	December 31, Balance	Notes
2014	-	2,286,114	-	(9,099,426)	11,385,540	Prepaid account was established in 2014 when the plan benefits were changed as of 1/1/2014 to reduce benefits.
2015	11,385,540	-	(670,988)	(11,512,656)	22,227,208	
2016	22,227,208	-	-	(9,183,550)	31,410,759	
2017	31,410,759	-	-	(7,909,433)	39,320,191	
2018	39,320,191	-	14,713	(12,433,762)	51,768,666	
2019	51,768,666	-	11,469	(9,980,399)	61,760,535	
2020	61,760,535	-	(33,361)	(13,159,718)	74,886,893	
2021	74,886,893	-	4,373	(14,631,621)	89,522,887	The Company's updated OPEB expense (credit) (Net Periodic Postretirement Benefit Cost) projection has been annualized based on latest forecast from Willis Towers Watson.
2022 Test Year	89,522,887	-	-	(10,801,000)	100,323,887	The Company's updated OPEB expense (credit) (Net Periodic Postretirement Benefit Cost) projection for 2022 is now approximately $(14.4) million based upon the latest forecast from Willis Towers Watson.

Indiana Michigan Power Company
FAS87 Prepaid Pension History
Amounts Presented on an I&M Total Company Basis

Year	Opening Balance	Contribution	Pension Expense (Net Periodic Pension Cost)	December 31, Balance	Notes
2005	-	-	-	84,582,060	
2006	84,582,060	-	8,486,486	76,095,574	
2007	76,095,574	-	6,794,836	69,300,738	
2008	69,300,738	-	6,418,354	62,882,384	
2009	62,882,384	-	12,484,766	50,397,618	
2010	50,397,618	63,207,452	18,292,201	95,312,868	
2011	95,312,868	49,556,000	14,218,000	130,650,869	
2012	130,650,869	21,202,000	15,465,540	136,387,329	
2013	136,387,329	-	20,266,081	116,121,248	
2014	116,121,248	8,629,000	18,781,622	105,968,626	
2015	105,968,626	13,704,000	16,423,418	103,249,208	
2016	103,249,208	12,150,000	12,906,325	102,492,883	
2017	102,492,883	12,418,000	12,597,191	102,313,691	
2018	102,313,691	-	9,040,859	93,272,832	
2019	93,272,832	-	6,450,738	86,822,094	
2020	86,822,094	6,431,000	11,751,032	81,502,062	
2021	81,502,062	-	15,578,339	65,923,724	The Company's updated pension expense (net periodic pension cost) projection has been annualized based on latest forecast from Willis Towers Watson. The Company no longer expects to make a contribution in 2021.
2022 Test Year	65,923,724	10,459,000	10,595,000	65,787,724	The Company's updated pension expense (net periodic pension cost) projection for 2022 is now approximately $16.4 million based upon the latest forecast from Willis Towers Watson.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 25
IURC CAUSE NO. 45576

DATA REQUEST NO OUCC 25-05

REQUEST

Pension and OPEB Prepayments: Please explain if the Company included the return on the prepaid pension and OPEB assets in the costs contributed by ratepayers. If not, please explain why the Company does not consider the return on the prepaid assets to be costs directly related to the Company's pension and OPEB costs and include the amount of pre-tax return on the prepaid pension and OPEB assets by year.

RESPONSE

I&M objects to the Request on the grounds and to the extent the Request is vague and ambiguous, particularly with respect to the undefined phrase "return on the prepaid pension and OPEB assets in the costs contributed by ratepayers". Subject to and without waiver of the foregoing objection, the Company responds as follows to the extent it understands the request.

The Company clarifies that the prepaid pension asset reflects shareholder contributions. Similarly, the prepaid OPEB asset reflects funds advanced by the Company to ratepayers. This is explained in the testimony of Company witness Ross (pages 24-35). The return earned by the Company on items included in the rate base component of the revenue requirement reflects compensation to the Company for the advancement of the funds used to create these assets. As such this is not a pension or OPEB trust contribution or a pension or OPEB cost.
As for the trust investments, pension expense required by the Company to be recorded under GAAP (Accounting Standards Codification 715) is net of the earned return on pension-related investments.

INDIANA MICHIGAN POWER COMPANY
Adjustment Summary
For the Test Year Ending December 31, 2022

Line	Description	Ref.	Witness	Rate Base	Pre-Tax ROR	Rate Increase
1	Requested Amounts[1]			$ 5,235,969,265		$ 110,713,174
2	Rate Base Adjustments					
3	Capitalized STI	Sch. MG-12	M. Garrett	$ (3,350,590)	7.606781%	$ (254,872)
4	Capitalized LTI	Sch. MG-13	M. Garrett	(1,875,926)	7.606781%	(142,698)
5	Remove Prepaid Pension Expense	Sch MG-16	M. Garrett	(127,429,283)	7.606781%	(9,693,266)
6	EV Fast Charging	Sch MG-9	Haselden	(3,783,088)	7.606781%	(287,771)
7	Flex Pay Program		Loveman	(568,770)	7.606781%	(43,265)
8	AMI Program		Alvarez	(20,200,000)	7.606781%	(1,536,570)
9	Combined Projects		Alvarez	(1,614,688)	7.606781%	(122,826)
10	Combined Projects		Alvarez	(28,078,466)	7.606781%	(2,135,867)
11	Deferred Bad Debt Expense		Blakley	(2,023,141)	7.606781%	(153,896)
12	Rockport Unit 2		Blakley	(72,779,725)	7.606781%	(5,536,194)
13	Cybersecurity		Lantrip	(11,976,146)	7.606781%	(910,999)
14	Total Rate Base Adjustments			$ (273,679,823)		$ (20,818,225)
15	Cost of Capital Adjustments					
16	Capital Structure	Sch. MG-21	M. Garrett	$ 4,962,289,442	-0.138469%	$ (6,871,210)
17	Return on Equity	9.10%	D. Garrett	$ 4,962,289,442	-0.510869%	(25,350,777)
18	Total Cost of Capital Adjustments					$ (32,221,987)
19	Operating Income Adjustments					
20	Vacant Positions	Sch. MG-11	M. Garrett			$ (8,088,829)
21	Short-Term Incentive Plans	Sch. MG-12	M. Garrett			$ (8,646,111)
22	Long-Term Incentive Plans	Sch. MG-13	M. Garrett			(5,640,187)
23	SERP	Sch. MG-14	M. Garrett			(151,543)
24	Pensions and Benefits	Sch. MG-15	M. Garrett			(1,990,473)
25	Factoring	Sch. MG-17	M. Garrett			(863,440)
26	Cybersecurity	Sch. MG-10	Lantrip			(3,855,395)
27	Nuclear Decommissioning Fund	Sch. MG-10	Eckert			(2,000,000)
28	Rate Case Expense	Sch. MG-10	Eckert			(403,493)
29	Flex Pay Program	Sch. MG-10	Loveman			(11,347)
30	Deferred Bad Debt Expense	Sch. MG-10	Blakley			(239,773)
31	Purchased Power Capacity	Sch. MG-10	Lantrip			(1,068,923)
32	Depreciation Adjustment	Sch. MG-18	D. Garrett			(29,905,443)
33	Rate Case Expense	Sch. MG-8	M. Garrett			(299,914)
34	Additional Uncollectible Accounts	Calc.	M. Garrett			(178,701)
35	Additional Utility Tax / Assessment	Calc.	M. Garrett			(948,851)
36	Other - Rounding Differences[2]					283,974
37	Total Adjustments to Operating Income					$ (64,008,449)
38	Total Adjustments					$ (117,048,660)
39	**Net Increase in Rates**					**$ (6,335,487)**

Notes

1/ Cause No. 45576, Financial Exhibit A, Exhibit A-1, Page 1 of 1, Line 7.

2/ The requested ROR is rounded but the return components are not resulting in cumulative rounding differences on rate base and rate of return issues.

INDIANA MICHIGAN POWER COMPANY
Determination of Revenue Increase/(Decrease)
For the Test Year Ending December 31, 2022

Line No.	Description			Amounts per Petitioner at Present Rates [1/]	Amount Per OUCC
1	Recommended Rate Base	1/		$ 5,235,969,265	$ 4,962,289,442
2	Required Rate of Return			6.08%	5.60%
3	Net Operating Income Required			$ 318,346,931	$ 277,902,412
4	Net Operating Income at Present Rates			236,820,294	282,572,534
5	Net Income Surplus/(Deficiency)			$ (81,526,637)	$ 4,670,122
6	Revenue Multiplier	2/		1.3580	1.3566
7	Base Rate Revenue Increase			$ 110,713,173	**$ (6,335,487)**
8	Remove Transmission Owner Costs, Revenues			(4,090,001)	(4,090,001)
9	Total Base Rate Revenue Increase			$ 106,623,172	$ (10,425,488)
10	Less: Current Revenue for Ongoing Riders			(243,618,128)	(243,618,128)
11	Plus: Proposed Rider Revenue			$ 241,383,612	$ 241,383,612
12	Total Rate Change Before Phase-In Credit			$ 104,388,656	$ (12,660,004)
13	**Verification**				
14	Revenue Increase/(Decrease)			$ 110,713,173	$ (6,335,487)
15	Less: IURC Fee		0.1274%	141,010	(8,069)
16	Bad Debt		0.3935%	435,630	(18,172)
17	State Taxable Income			$ 110,136,533	$ (6,309,246)
18	State Income Tax		4.9714%	5,475,275	(309,258)
19	Indiana Utility Receipts Tax		1.4000%	1,543,886	(88,442)
20	Federal Taxable Income			$ 103,117,372	$ (5,911,546)
21	Federal Income Tax		21.0000%	21,654,648	(1,241,425)
22	Net Income Surplus/(Deficiency)			$ (81,462,724)	$ 4,670,121

Notes:

23 1/ Per I&M Exhibit A-1.

Line No.	Description	Per I&M Exhibit A-8 Tax Rates	Per I&M Exhibit A-8	Per OUCC Tax Rates	Per OUCC
24	2/ Calculation of Conversion Factor				
25	Operating Revenues		100.00%		100.00%
26	Less: Uncollectible Accounts Expense		0.3935%		0.2868%
27	Income Before Income Taxes		99.61%		99.71%
28	Less: Indiana Utility Receipts Tax	**1.4000%**		1.4000%	
29	Public Utility Assessment Fee (IURC)	**0.1274%**	1.5214%	0.1274%	1.5230%
30	Base Subject to State Income Taxes		98.0851%		98.1902%
31	Less: State Income Taxes (Line 6 x E	**4.9714%**	4.8762%	4.9714%	4.8814%
32	Income Before Federal Income Taxes		93.2089%		93.3088%
33	Less: Federal Income Taxes (Line 8 ›	**21.00%**	19.5739%	21.00%	19.5948%
34	Operating Income Percentage		73.6350%		73.7140%
35	Gross Revenue Conversion Factor (100% / Line 10)		1.3580		1.3566
36	Combined State Tax Rate		6.8637%		6.8637%

INDIANA MICHIGAN POWER COMPANY
Summary of Operating Income
For the Test Year Ending December 31, 2022

Line No.	Description		Petitioner Amounts at Present Rates	OUCC Adjustments	Amounts per OUCC at Present Rates	Revenue Increase/ (Decrease)	Amounts After Revenue Incr. / (Decr.)
1	Total Operating Revenues	1/	$ 1,557,042,829	$ -	$ 1,557,042,829	$ (6,335,487)	$ 1,550,707,342
	Operating Expenses						
2	Operation and Maintenance		$ 853,365,602	$ (32,070,182)	$ 821,295,420	$ (26,241)	$ 821,269,179
3	Depreciation & Amortization		349,159,750	(29,905,443)	319,254,307		319,254,307
4	Regulatory Debits and Credits		1,310,661		1,310,661		1,310,661
5	Taxes Other Than Income		92,031,060	(1,189,246)	90,841,814	(88,442)	90,753,372
6	State Income Taxes		(2,180,460)	3,446,988	1,266,528	(309,258)	957,270
7	Federal Income Taxes		26,535,922	13,965,642	40,501,565	(1,241,425)	39,260,140
8	Total Operating Expenses		$ 1,320,222,535	$ (45,752,240)	$ 1,274,470,295	$ (1,665,366)	$ 1,272,804,929
9	Utility Operating Income		$ 236,820,294	$ 45,752,240	$ 282,572,534	$ (4,670,121)	$ 277,902,413
10	Rate Base		$ 5,235,969,265		$ 4,962,289,442		$ 4,962,289,442
11	Rate of Return		**4.52%**		**5.69%**		**5.60%**
				$ (63,164,871)			

Notes:

1/ Exhibit A-5, p. 1, Col (9).

INDIANA MICHIGAN POWER COMPANY
Summary of Rate Base
For the Test Year Ending December 31, 2022

Description	Indiana Jurisdictional Amount per Petitioner 1/	OUCC Adjustments	Adjusted Per OUCC
Electric Plant in Service	$ 7,486,549,124	$ (143,658,629)	$ 7,342,890,495
Accumulated Depreciation & Amortization	(2,616,576,625)	-	(2,616,576,625)
Net Utility Plant in Service	4,869,972,499	(143,658,629)	4,726,313,870
Prepaid Pension (and OPEB) Expense	$ 127,429,283	$ (127,429,283)	$ (0)
Deferred Gain Rockport 2 Sale	-	-	-
Fuel Stock	44,262,887	-	44,262,887
Other Materials & Supplies	124,608,354	-	124,608,354
Regulatory Assets	52,022,065	(2,591,911)	49,430,154
Regulatory Liabilities	-	-	-
Allowance Inventory	17,674,176		17,674,176
Deferred Income Taxes	-	-	-
Original Cost Rate Base	$ 5,235,969,265	$ (273,679,823)	$ 4,962,289,442

Notes:
1/ Exhibit A-6, Page 1.

INDIANA MICHIGAN POWER COMPANY
Summary of Adjustments to Rate Base
For the Test Year Ending December 31, 2022

Line No.	Description	Source	Amount
1	Rate Base per Petitioner's Filing	Exhibit A-6, Page 1.	$ 5,235,969,265
2	OUCC Adjustments		
3	Capitalized STI	MG-12	$ (3,350,590)
4	Capitalized LTI	MG-13	(1,875,926)
5	Remove Prepaid Pension and Expense	MG-16	(127,429,283)
6	EV Fast Charging	MG-9	(3,783,088)
7	Flex Pay Program	MG-9	(568,770)
8	AMI Program	MG-9	(20,200,000)
9	Combined Projects	MG-9	(1,614,688)
10	Combined Projects	MG-9	(28,078,466)
11	Deferred Bad Debt Expense	MG-9	(2,023,141)
12	Rockport Unit 2	MG-9	(72,779,725)
13	Cybersecurity	MG-9	(11,976,146)
14	Total OUCC Adjustments		$ (273,679,823)
15	OUCC Adjusted Rate Base		$ 4,962,289,442

INDIANA MICHIGAN POWER COMPANY
Summary of Adjustments to Net Income
For the Test Year Ending December 31, 2022

Line	Description	Revenues	O&M Expenses	Depreciation Expense	Payroll Tax	Bad Debt	Taxes Other Than Income	State Taxes	Federal Income Taxes	Net Operating Income
1	Net Income per Petitioner	$ 1,557,042,829	$ 853,365,602	$ 349,159,750			$ 92,031,060	$ (2,180,460)	$ 26,535,922	$ 238,130,955
2							$262,486,417			
3	OUCC Adjustments					$ -	$ -			
4	Vacant Positions	$ -	**$ (7,514,007)**	$ -	$ (574,822)			$ 402,128	$ 1,614,207	$ 6,072,494
5	STI Compensation	-	(8,031,687)	-	(614,424)			429,833	1,725,418	6,490,860
6	LTI Compensation	-	(5,640,187)	-				280,396	1,125,556	4,234,234
7	Supplemental Pension	-	(151,543)	-	-			7,534	30,242	113,767
8	Pensions and Benefits	-	(1,990,473)	-	-			98,954	397,219	1,494,300
9	Factoring Expense	-	(863,440)	-				42,925	172,308	648,207
10	Cybersecurity		(3,855,395)					191,667	769,383	2,894,345
11	Nuclear Decommissioning	-	(2,000,000)	-	-			99,428	399,120	1,501,452
12	Rate Case Expense	-	(403,493)	-	-			20,059	80,521	302,913
13	Flex Pay Program Expenses	-	(11,347)	-	-			564	2,264	8,518
14	Deferred Bad Debt Expense	-	(239,773)	-				11,920	47,849	180,004
15	Purchased Power Capacity	-	(1,068,923)	-				53,140	213,314	802,468
16	Depreciation Rate Adjustment	-	-	(29,905,443)	-			1,486,719	5,967,932	22,450,792
17	Rate Case Exp. Amortization		(299,914)					14,910	59,851	225,153
18	Interest Synchronization	-	-	-	-			306,810	1,360,457	(1,667,267)
19	Total OUCC Adjustments	$ -	$ (32,070,182)	$ (29,905,443)	$ (1,189,246)	$ -	$ -	$ 3,446,988	$ 13,965,642	$ 45,752,240
20	OUCC Adjusted Net Income	$ 1,557,042,829	$ 821,295,420	$ 319,254,307	$ (1,189,246)	$ -	$ 92,031,060	$ 1,266,528	$ 40,501,565	$ 283,883,195

INDIANA MICHIGAN POWER COMPANY
Summary of Adjustments to Net Income
For the Test Year Ending December 31, 2022

Line No.	Description	Ref.	Amount
1	Net Income per Petitioner (I&M Exhibit A-5, p.1)		$ 236,820,294
2	OUCC Adjustments		
3	Vacant Positions	MG-6	6,072,494
4	STI Compensation	MG-6	6,490,860
5	LTI Compensation	MG-6	4,234,234
6	Supplemental Pension	MG-6	113,767
7	Pensions and Benefits	MG-6	1,494,300
8	Factoring Expense	MG-6	648,207
9	Cybersecurity	MG-6	2,894,345
10	Nuclear Decommissioning	MG-6	1,501,452
11	Rate Case Expense	MG-6	302,913
12	Flex Pay Program Expenses	MG-6	8,518
13	Deferred Bad Debt Expense	MG-6	180,004
14	Purchased Power Capacity	MG-6	802,468
15	Depreciation Rate Adjustment	MG-6	22,450,792
16	Rate Case Expense	MG-6	225,153
17	Interest Synchronization	MG-6	(1,667,267)
18	Total OUCC Adjustments		$ 45,752,240
19	Net Income Per OUCC		$ 282,572,534

INDIANA MICHIGAN POWER COMPANY
Rate Case Expense Adjustment
For the Test Year Ending December 31, 2022

Line No.	Description	I&M Proposed Rate Case Expense [1/] (Indiana Direct)	Exclusion Percent	OUCC Proposed Rate Case Expense (Indiana Direct)	Adjustment
1	Legal Services	$ 1,480,000		$ 1,480,000	
2	CCA Training	134,485	100%	- [2/]	
3	Equity Return Study and Testimony	117,000		117,000	
4	Decommissioning Study Testimony	5,000		5,000	
5	Publication of Notice	3,823		3,823	
6	AMI Cost Benefit Study	672,500	100%	- [2/]	
7	AMI Study Testimony	168,000		168,000	
8	Transcript Expense	5,049		5,049	
9	Witness Hearing Expense	20,613		20,613	
10	Total O&M	$ 2,606,470		$ 1,799,485	
11	Amortization Period (years)	2		3	
12	Annual Rate Case Expense	$ 1,303,235		$ 599,828	$ (703,407)
13	Other OUCC Adjustments				(403,493)
14	Net Rate Case Expense Amortization Adjustment				**$ (299,914)**

Notes:
1/ WP-OM-5
2/ OUCC witness Michael Eckert

INDIANA MICHIGAN POWER COMPANY
Rate Base Adjustments Sponsored by Other Witnesses
For the Test Year Ending December 31, 2022

Line No.	Description	OUCC Witness	Total Company Adjustment	Jurisdictional Factor [1/]	Indiana Jurisdictional Amount
1	EV Fast Chargers	Haselden		Direct	$ (3,783,088)
2	Flex Pay Program	Loveman		Direct	(568,770)
3	AMI Program	Alvarez		Direct	(20,200,000)
4	Combined Projects	Alvarez		Direct	(1,614,688)
5	Combined Projects	Alvarez		Direct	(28,078,466)
6	Deferred Bad Debt Expense	Blakley		Direct	(2,023,141)
7	Rockport Unit 2	Blakley		Direct	(72,779,725)
8	Cybersecurity	Lantrip	$ (16,254,261)	73.680042%	(11,976,146)
9	Total Rate Base Adjustments				$ (141,024,024)

Notes:
1/ Composite allocation factors

INDIANA MICHIGAN POWER COMPANY
Adjustment to Operating Income Sponsored by Other OUCC Witnesses
For the Test Year Ending December 31, 2022

Line No.	Description	OUCC Witness	Total Company Adjustment	Jurisdictional Factor 1/	Indiana Jurisdictional Amount
1	Cybersecurity	Lantrip	5,418,213	71.1562%	$ 3,855,395
2	Nuclear Decommissioning Fund	Eckert		Direct	2,000,000
3	Rate Case Expense	Eckert		Direct	403,493
4	Flex Pay Program	Loveman		Direct	11,347
5	Deferred Bad Debt Expense	Blakley		Direct	239,773
6	Purchased Power Capacity	Lantrip	1,512,000	70.6960%	1,068,923
7	Total Adjustments				$ 7,578,931

Notes:

1/ Per OUCC witness Watkins Attachment GAW-3.

INDIANA MICHIGAN POWER COMPANY
Adjustment to Remove Unfilled Positions from Payroll Expense
For the Test Year Ending December 31, 2022

Line No.	Description		I&M Payroll
1	Test Year Wages and Salaries	1/	$ 236,815,000
2	Budgeted Employees	1/	2,105
3	Average Cost Per Employee		$ 112,501
4	Average Unfilled Positons	2/	140.6
5	Overstated Cash Compensation		$ 15,817,667
6	Payroll Expense Percentage	3/	66.76%
7	Overstated Payroll Expense		$ 10,559,874
8	Payroll Expense Adjustment for Unfilled Positions		$ (10,559,874)
9	Indiana Jurisdictional Factor	4/	71.1562%
10	Indiana Jurisdictional Adjustment		$ (7,514,007)
11	Adjustment to I&M Payroll Taxes at 7.65%		$ (807,830)
12	Adjustment to Indiana Jurisdictional Payroll Taxes		$ (574,822)

Notes:
1/ OUCC 6-3 Attachment 1.
2/ Average employee difference for 2016 through 2020 from OUCC 6-5, Attachment 1 and OUCC 6-4, Attachment 1.
3/ OUCC 6-1, Attachment 1.
4/ Exhibit A-5, column (9), line 11 plus line 12 divided by column (8) line 11 plus line 12.

INDIANA MICHIGAN POWER COMPANY
Adjustment to Remove Short-Term Incentive Compensation Expense Associated with Shareholders' Interest
For the Test Year Ending December 31, 2022

Line No.	Description	I&M Short-Term Incentives		Composite Allocation Factors		Indiana Jurisdictional Amount
1	Short-Term Incentive in O&M Expenses					
2	2020 Short-Term Incentives - I&M	$ 17,024,180	[1]	70.1046%	[3]	$ 11,934,733
3	2020 Short-Term Incentives - AEPSC	5,848,520	[1]	70.5929%	[3]	4,128,641
4	Total Short-Term Incentives	$ 22,872,700				$ 16,063,373
5	Financial Funded ICP Percentage	50%	[2]			50%
6	Financial Funded ICP	$ 11,436,350				$ 8,031,687
7	Adjustment to Remove Long-Term Incentives	$ (11,436,350)				$ (8,031,687)
8	FICA Tax at 7.65%	(874,881)				(614,424)
9	Total Short-Term Incentive Adjustment	$ (12,311,231)				$ (8,646,111)
10	Capitalized Incentives					
11	2020 Capitalized Short-Term Incentives - IMPC	$ 3,858,290	[1]	78.3062%	[4]	$ 3,021,282
12	2020 Capitalized Short-Term Incentives - AEPSC	4,428,180	[1]	72.3478%	[4]	3,203,689
13	Total Short-Term Incentives	$ 8,286,470				$ 6,224,971
14	Financial Funded ICP Percentage	50%				50%
15	Financial Funded ICP	$ 4,143,235				$ 3,112,485
16	Adjustment to Remove Short-Term Incentives	$ (4,143,235)				$ (3,112,485)
17	FICA Tax at 7.65%	(316,957)				(238,105)
18	Total Short-Term Incentive Adjustment	$ (4,460,192)				$ (3,350,590)

Notes:
1/ OUCC 5-13 Attachment 1
2/ MSFR: 1-5-8(a)-12 Attachment 1, page 2 of 15.
3/ Attachment JCD-1, page 1
4/ Attachment JCD-1, pages 2 and 3

INDIANA MICHIGAN POWER COMPANY
Adjustment to Remove Long-Term Incentive Compensation Expense Associated with Shareholders' Interest
For the Test Year Ending December 31, 2022

Line No.	Description	I&M Short-Term Incentives		Composite Allocation Factors		Indiana Jurisdictional Amount
1	Long-Term Incentive in O&M Expenses					
2	2022 Long-Term Incentives - IMPC	$ 3,770,170	1/	71.1562%	2/	$ 2,682,709
3	2022 Long-Term Incentives - AEPSC	4,156,320	1/	71.1562%	2/	2,957,478
4	Total Long-Term Incentives	$ 7,926,490				$ 5,640,187
5	Adjustment to Remove Long-Term Incentives for O&M Expenses	$ (7,926,490)				$ (5,640,187)
6	Capitalized Incentives					
7	2020 Capitalized Long-Term Incentives - IMPC	$ 382,460	3/	80.1732%	4/	$ 306,631
8	2020 Capitalized Long-Term Incentives - AEPSC	2,160,490	3/	72.6361%	4/	1,569,295
9	Total Long-Term Incentives	$ 2,542,950				$ 1,875,926
10	Adjustment to Remove Long-Term Incentives from Rate Base	$ (2,542,950)				$ (1,875,926)

Notes:
1/ OUCC 5-2 Attachment 1
2/ Exhibit A-5, column (9), line 11 plus line 12 divided by column (8) line 11 plus line 12.
3/ OUCC 5-3 Attachment 1

INDIANA MICHIGAN POWER COMPANY
Adjustment to Remove Supplemental Pension Plan Expense
For the Test Year Ending December 31, 2022

Line No.	Description		Amount
1	2022 Non-Qualified Pension Plans - Service Cost	1/	$133,000
2	2022 Pension O&M Expense Factor	2/	0.73662999
3	2022 Non-Qualified Pension Plan Service Cost Expense		$97,972
4	2022 Non-Qualified Pension Plans - Non-Service Cost	3/	$115,000
5	Total Non-Qualified Pension Expense		$212,972
6	Adjustment to Remove Non-Qualified Pensions		($212,972)
7	Composite Jurisdictional O&M Allocation Factor	4/	71.1562%
8	Adjustment to Jurisdictional Expenses		($151,543)

Notes:
1/ MSFR: 1-5-8(a)(13) Projected, line 12; Vol. II. Pg. 115
2/ MSFR: 1-5-8(a)(13) Projected, 1 minus line 19 divided by Line 3 plus line 12.
3/ MSFR: 1-5-8(a)(13) Projected, line 15; Vol. II. Pg. 115
4/ Exhibit A-5, column (9), line 11 plus line 12 divided by column (8) line 11 plus line 12.

INDIANA MICHIGAN POWER COMPANY
Adjustment to Employee Benefits
For the Test Year Ending December 31, 2022

Line No.	Description	Reference			Amount
1	2020 Pension and Benefits Expense				$18,149,825 [1]
2	2020 SERP Service Cost	(.pdf p. 235)	$122,490 [2]		
3	2020 Pension O&M Factor		0.706954527 [3]		
4	SERP Service O&M Expense		$86,595		
5	SERP Non-Service Cost		$97,036 [2]		
6	SERP O&M		$183,631		($183,631)
7	2020 Pensions and Benefits Expense Excluding SERP				$17,966,194
8	Increase Factor	2 Years @	2.10%	[4]	1.042441
9	Adjusted Pension and Benefits Expense for 2022				$18,728,697
10	Requested Pension and Benefits Expense		$21,739,000 [5]		
11	Less Recommended SERP Adjustment		(212,972) [6]		
12	Adjusted Protected Pensions and Benefits				21,526,028
13	Adjustment to Pension and Benefits Expense				($2,797,331)
14	Composite Jurisdictional O&M Allocation Factor				71.1562%
15	Adjustment to Jurisdictional Expenses				($1,990,473)

Notes:
1/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, line 29; (Vol. II. Pg. 116)
2/ MSFR: 1-5-8(a)(15)Attachment 2, page 29 of 29; (Vol. II. Pg. 235)
3/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, O&M line 8 divided by line 4.
4/ Bureau of Labor Statistics - Employment Cost Index for Benefits - June 2021 News Release.
5/ MSFR: 1-5-8(a)(13) Projected, line 24; Vol. II. Pg. 115
6/ Exhibit MG-14, line 6.

119.8%

INDIANA MICHIGAN POWER COMPANY
Remove Prepaid Pension Asset
For the Test Year Ending December 31, 2022

Line No.	Description		Total Company Amount	Indiana Retail Factor[3]	Indiana Retail Amount
1	Prepaid OPEB Costs	1	$ 96,252,892	72.0233%	$ 69,324,472
2	Adjustment to Prepaid OPEB Costs		$ (96,252,892)		$ (69,324,472)
3	Prepaid Pension Expense	2	$ 80,675,062	72.0233%	$ 58,104,811
4	Adjustment to Prepaid Pension Expense		$ (80,675,062)		$ (58,104,811)
5	Total Adjustment to Pension and OPEB Prepayments		$ (176,927,954)		$ (127,429,283)

Notes:
1/ See Exhibit A-2, page 2, account Prepaid OPEB Benefits (165.0035).
2/ See Exhibit A-2, page 2, account Prepaid Pension Benefits (165.0010).
3/ See Exhibit A-6, line 7, column 8 divided by column 7.

INDIANA MICHIGAN POWER COMPANY

Adjustment to Normalize Factoring Expense
For the Test Year Ending December 31, 2022

Line No.	Description	Amount
1	3-Year Average Factoring Expense	$ 10,853,994
2	Test Year Factoring Expense	11,921,155 [2]
		9,645,407
3	Adjustment to O&M Expense	$ (1,067,161)
4	Jurisdictional Allocation Factor	80.9100% [2]
5	Adjustment to Indiana Jurisdictional O&M Expenses	$ (863,440)

Line No.		2018 [1]	2019 [2]	2020 [2]	3-YR AVG
6	Three Year Average Factoring Expense ($000)				
7	Customer A/R Exp	$ 5,793	$ 5,872	$ 4,273	$ 5,313
8	Fact Cust A/R Bad Debts	3,762	5,019	7,843	5,541
9	Total Company	$ 9,555	$ 10,891	$ 12,116	$ 10,854
10	Receivables Sold ($000,000)	$ 1,890	$ 1,873	$ 1,993	$ 1,919
11	Bad Debt Rate	0.1990%	0.2680%	0.3935%	0.2868%

Notes:
1/ OUCC_22-5, Attachment 1
2/ WP-OM-1

INDIANA MICHIGAN POWER COMPANY
Adjustment to Depreciation Expense
For the Test Year Ending December 31, 2022

Line No.	Description	Depreciable Plant [1]	OUCC Adjustments to Plant	OUCC Adjusted Plant	OUCC Proposed Rates [2]	OUCC Total Company Depreciation Expense	Indiana Jurisdictional Factors	OUCC Indiana Jurisdictional Depreciation
1	Fossil	$ 963,936,875	$ (104,385,934)	$ 859,550,941	9.690%	$ 83,290,486	70.6960%	$ 58,883,042
2	Hydro	57,573,340		57,573,340	4.260%	2,452,624	70.6960%	1,733,907
3	Nuclear	3,550,276,644	(1,570,378)	3,548,706,266	4.520%	160,401,523	70.7454%	113,476,627
4	Other	66,840,765	-	66,840,765	5.330%	3,562,613	70.6960%	2,518,625
5	Transmission	1,865,181,058	(1,079,685)	1,864,101,373	2.530%	47,161,765	70.6960%	33,341,482
6	Distribution	3,096,976,209	(69,635,193)	3,027,341,016	2.380% [5]	72,050,716	80.4493%	57,640,262
7	General	179,974,956	(17,161,459)	162,813,496	4.000%	6,512,540	73.0994%	4,760,625
8	Totals	$ 9,780,759,844	$ (193,832,648)	$ 9,586,927,196		$ 375,432,267		$ 272,354,569
9						413,630,754 [3]		302,260,012 [4]
10	Adjustment to Depreciation Expense					$ (38,198,487)		$ (29,905,443)

Notes:
1/ file 45576_IndMich_WP-A-DEP-2_Depreciation Adjustment_07012021.xlsx, tab WP-Deprec Adj, cells D7-D14
2/ Recommended by OUCC witness David Garrett.
3/ From WP-Exhibit A-5, tab Adjustments, total of cells AH209 - AH213.
4/ From WP-Exhibit A-5, tab Adjustments, total of cells AI209 - AI213.
5/ Rate recommended for Indiana distribution plant.

INDIANA MICHIGAN POWER COMPANY
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2022

Line No.	Description	Amount	
1	Rate Base per OUCC	$ 4,962,289,442	1/
2	Synchronized Interest Rate	1.790%	2/
3	Tax Deductible Interest per OUCC	$ 88,824,981	
4	Tax Deductible Interest per I&M	94,996,539	3/
5	Increase in Taxable Income	$ 6,171,558	
6	State Income tax effect at 4.9714%	$ 306,810	
7	Federal Income Tax Effect at 21%	$ 1,360,457	
8	Total Tax Change	$ 1,667,267	

Notes
1/ Exhibit MG-4
2/ Exhibit MG-20
3/
45576_IndMich_WP_HNC01 - Test Year Tax Expense Calculations_07012021.xlsx, tab Summary, line 2, column 9.

INDIANA MICHIGAN POWER COMPANY
OUCC Capital Structure and Rate of Return
For the Test Year Ending December 31, 2022

Line No.	Description	Amount [1/]	Capitalization Ratio [1/]	Cost Rate [1/]	Weighted Cost Rate	Revenue Conversion Factor	Pre-Tax Rate of Return
1	Prepaid Pension and NOLC ADIT Adjustment						
2	Long-Term Debt	$2,820,079,888	40.15%	4.44%	1.782677%	1	1.782677%
3	Common Equity	2,927,644,814	41.68%	10.00%	4.168182%	1.3566	5.654555%
4	Customer Deposits	41,698,455	0.59%	2.00%	0.011873%	1	0.011873%
5	Accum. Def. FIT	1,220,692,023 [3/]	17.38%	0.00%	0.000000%	1	0.000000%
6	Accum. Def. JDITC	13,678,705	0.19%	7.27%	0.014158%	1.3566	0.019207%
7	Total	$ 7,023,793,885	100.00%		5.976890%		7.468312%
8	Adjustment to the Weighted Cost of Capital				-0.103110%		-0.138469%
9	ROE Adjustment						
10	Long-Term Debt	$2,820,079,888	40.15%	4.44%	1.7827%	1	1.782660%
11	Common Equity	2,927,644,814	41.68%	9.10% [2/]	3.7929%	1.3566	5.145421%
12	Customer Deposits	41,698,455	0.59%	2.00%	0.0118%	1	0.011800%
13	Accum. Def. FIT	1,220,692,023	17.38%	0.00%	0.0000%	1	0.000000%
14	Accum. Def. JDITC	13,678,705	0.19%	6.81%	0.0129%	1.3566	0.017563%
15	Total	$ 7,023,793,885	99.99%		5.600286%	1.2423372	6.957444%
16	Adjustment to the Weighted Cost of Capital				-0.3766%		-0.510869%
17	AJDITC Cost Rate						
18	Long-Term Debt	$ 2,820,079,888	49.06%	4.44%	2.18%		
19	Common Equity	2,927,644,814	50.94%	9.10% [2/]	4.64%		
		$ 5,747,724,702	100.00%		6.81%		
20	Synchronized Interest Rate						
21	Long-Term Debt	$ 2,820,079,888	40.15%	4.44%	1.78%		
22	Common Equity	2,927,644,814	41.68%		0.00%		
23	Customer Deposits	41,698,455	0.59%	2.00%	0.01%		
24	Accum. Def. FIT	1,220,692,023	17.38%		0.00%		
25	Accum. Def. JDITC	13,678,705	0.19%		0.00%		
26	Total	$ 7,023,793,885	99.99%		1.79%		

Notes:
1/ Exhibit A-7, Page 3 of 4.
2/ Recommended by David Garrett on behalf of OUCC.
3/ See Schedule MG-22

INDIANA MICHIGAN POWER COMPANY
I&M Capital Structure and Rate of Return
For the Test Year Ended December 31, 2020

Line No.	Description	Amount	Capitalization Ratio	Cost Rate	Weighted Cost Rate	Revenue Conversion Factor	Pre-Tax Rate of Return
1	Long-Term Debt [1/]	$2,820,079,888	40.86%	4.44%	1.814307%	1	1.814307%
2	Common Equity	2,927,644,814	42.42%	10.00%	4.242137%	1.3580	5.760822%
3	Customer Deposits	41,698,455	0.60%	2.00%	0.012084%	1	0.012084%
4	Accum. Def. FIT	1,098,242,295	15.91%	0.00%	0.000000%	1	0.000000%
5	Accum. Def. JDITC	13,678,705	0.20%	7.27%	0.014409%	1.3580	0.019568%
6	Total	$ 6,901,344,157	100.00%		6.080000%	1.2511153	7.606781%
7	AJDITC Cost Rate						
8	Long-Term Debt	2,820,079,888	49.06%	4.44%	2.18%		
9	Common Equity	2,927,644,814	50.94%	10.00%	5.09%		
		5,747,724,702	100.00%		7.27%		
10	Synchronized Interest Rate						
11	Long-Term Debt	$ 2,820,079,888	40.86%	4.44%	1.81%		
12	Common Equity	2,927,644,814	42.42%		0.00%		
13	Customer Deposits	41,698,455	0.60%	2.00%	0.01%		
14	Accum. Def. FIT	1,098,242,295	15.91%		0.00%		
15	Accum. Def. JDITC	13,678,705	0.20%		0.00%		
16	Total	$ 6,901,344,157	100.00%		1.82%		

Notes:
1/ Exhibit A-7, page 3.

2/ Calculation of Conversion Factor

	Per I&M Exhibit A-8 Tax Rates		Per OUCC Tax Rates	
Operating Revenues		100.00%		100.00%
Less: Uncollectible Accounts Expense		0.3935%		0.2868%
Income Before Income Taxes		99.61%		99.71%
Less: Indiana Utility Receipts Tax	1.4000%		1.4000%	
Public Utility Assessment Fee (IURC)	0.1274%	1.5214%	0.1274%	1.5230%
Base Subject to State Income Taxes		98.0851%		98.1902%
Less: State Income Taxes (Line 6 x Effective State Tax F	4.9714%	4.8762%	4.9714%	4.8814%
Income Before Federal Income Taxes		93.2089%		93.3088%
Less: Federal Income Taxes (Line 8 x Federal Tax Rate)	21.00%	19.5739%	21.00%	19.5948%
Operating Income Percentage		73.6350%		73.7140%
Gross Revenue Conversion Factor (100% / Line 10)		1.3580		1.3566
Combined State Tax Rate		6.8637%		6.8637%
		1.019522594		

INDIANA MICHIGAN POWER COMPANY
Adjustment to Uncollectible Accounts and Revenue Taxes
For the Test Year Ending December 31, 2022

Line No.	Description		Amount
1	I&M Requested ADFIT		$ 1,098,242,295 [1/]
2	OUCC Adjustment to Exclude the NOLC		159,604,598 [2/]
3	Prepaid Pension Asset Adjustment	$ (176,927,954) [3/]	
4	Federal Tax Rate	21%	
5	Adjustment to ADFIT to Exclude the Prepaid Pension Asset	$ (37,154,870)	$ (37,154,870)
6	OUCC Adjusted ADFIT Balance		$ 1,220,692,023

Notes:
1/ Exhibit A-7, page 3, line 5.
2/ See the Direct Testimony of Jessica M. Criss, page 18, line 8 and Attachment JMC-3
3/ Schedule MG-15

CERTIFICATE OF SERVICE

This is to certify that a copy of the Indiana Office of Utility Consumer Counselor's Testimony Filing has been served upon the following parties of record in the captioned proceeding by electronic service on October 12, 2021.

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