**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

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|---|---|---|
| **PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.** | ) | **CAUSE NO. 45235** |

**INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR**

**PUBLIC'S EXHIBIT NO. 2**

**TESTIMONY OF OUCC WITNESS**

**MARK E. GARRETT**

**August 20, 2019**

Respectfully submitted,

Tiffany T. Murray
Attorney No. 28916-49
Deputy Consumer Counselor

PUBLIC'S EXHIBIT NO. 2

**BEFORE THE**

**INDIANA UTILITY REGULATORY COMMISSION**

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| **INDIANA MICHIGAN POWER COMPANY** | )<br>)<br>) | **CAUSE NO. 45235** |

**DIRECT TESTIMONY AND EXHIBITS**

**OF**

**MARK E. GARRETT**

**ON BEHALF OF**

**INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR ("OUCC")**

**August 20, 2019**

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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, Massachusetts, Nevada, Oklahoma, 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 to this testimony as Appendix 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 $172.005 million increase in rates. This represents an increase of 11.75% in Indiana jurisdictional revenues. 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-21 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. 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 $17.902 million for I&M annual incentive expense and $5.823 million for AEPSC allocated annual incentive expense, for a total of $23.726 million annual incentive plan costs based on projected expense levels for test year ended December 31, 2020.[1]

**Q: DO COMPANY WITNESSES DISCUSS THE ANNUAL INCENTIVE COMPENSATION PLANS IN DIRECT TESTIMONY?**

A: No. AEP/I&M's incentive compensation plans are not supported, or otherwise 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.[2]

**Q: FROM YOUR REVIEW OF THE COMPANY'S PLANS, DO FINANCIAL PERFORMANCE MEASURES COMPRISE A SIGNIFICANT COMPONENT OF THE INCENTIVE COMPENSATION METRICS?**

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[1] See I&M's response to OUCC 9-24, Attachment 2019-2020 ICP.pdf.
[2] Minimum Standard Filing Requirements of Indiana Michigan Power Company ("MSFR"), Vol. 2 of 3, pp. 23-47.

A: Yes. The Company's Annual Compensation plans are heavily dependent on financial performance measures. The funding for annual incentive compensation is driven primarily by AEP's earnings per share (EPS). For both 2018 and 2019, 70% of the Company's incentive compensation plan metrics are based on AEP achieving EPS targets:

| | |
|---|---|
| 2018 | $3.70 per share[3] |
| 2019 | $3.95 per share[4] |

Moreover, the plans have a funding *trigger* so that if AEP's EPS targets are not met, the plans would not be funded. In other words, even though the Company's performance measures include both financial and operational factors, the actual funding is tied 70% to financial performance and the only *funding* trigger is directly tied to financial performance. The 2019 plan states:

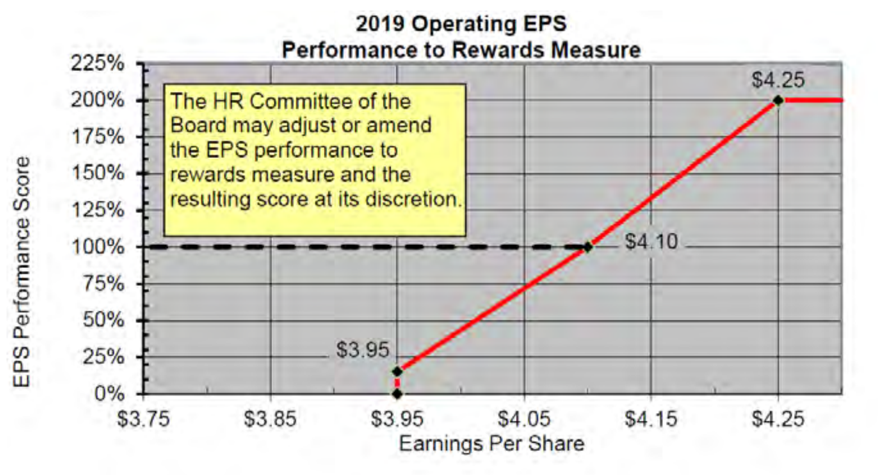
> As in past years, the CEO and HR Committee of the Board have ***discretion*** to adjust annual incentive funding. All incentive plan ***funding is contingent*** on AEP achieving operating earnings of at least $3.95 per share for 2019.[5]

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 funding for the plan would be 0%. Thus, the Company's EPS is the primary controlling factor in determining whether: (1) the incentive compensation will be paid, and (2) to what extent.

**Q: HOW DOES THE FUNDING MECHANISM WORK?**

[3] See MSFR Vol 2 of 3, p. 23, 1-5-8(a)(12)(2018), p. 2 of 12.
[4] See MSFR Vol 2 of 3, p. 35, 1-5-8(a)(12)(2019), p. 2 of 13.
[5] Id., p. 2 of 13.

A: Not only is there an EPS funding trigger (minimum threshold) of $3.95 for 2019, but the plan also provides for ***increasing*** levels of funding for employee incentives based on AEP's achievement of ***higher*** earnings levels. If AEP achieves an EPS of $4.10, the funding of the annual plan would be 100%. If AEP achieves an EPS of $4.25, the funding level would be 200%, as shown in this chart, excerpted from the Company's 2019 Annual Incentive Compensation Plan:[6]




As shown in this chart, if EPS is less than $3.95, there is no incentive payment. In that event, the employees would receive no incentive compensation and the Company would retain the amount included in rates for the benefit of shareholders.

**Q: DOES THIS MEAN THAT THE ANNUAL INCENTIVE COMPENSATION PLANS ARE DISCRETIONARY AND CONTINGENT ON THE COMPANY'S FINANCIAL PERFORMANCE?**

A: Yes. AEP's HR Committee may adjust or amend plan funding at its discretion and all

[6] See Chart in AEP's Plan in MSFR Vol 2 of 3, p. 36, 1-5-8(a)(12)(2019), p. 2 of 13.

funding ***is contingent*** on AEP achieving its target operating earnings:

> The Committee has sole authority to amend or terminate the Plan and *may do so at any time, for any reason, either with or without notice*. The Committee may adopt, delete, modify or adjust performance objectives, metrics and weights *at any time, including after the conclusion of a Plan Year*, should the Committee determine that changes in AEP's structure or other significant business situations would produce an Overall Score or awards for a Plan Year that are not reflective of the underlying economics or performance of the business. The Committee may also modify the eligibility criteria for the Plan, *add or delete individual participants or groups of participants and adjust any or all award payouts*. [7]

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

A: Yes. Plans that are heavily weighted on EPS targets, and those that have an EPS trigger, clearly prioritize maximizing shareholders' earnings. AEP's plan acknowledges that ensuring earnings for its shareholders is an essential part of the plan. One of its stated reasons for the 70% 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…[8]

This excerpt demonstrates that AEP's plan is designed to place shareholders' interests first—that is, the Company will ensure target shareholder earnings levels are satisfied before employees are paid any incentive compensation. From a ratemaking perspective, this means that money collected from ratepayers for the purpose of paying employee incentives may not be paid to employees but instead may be diverted, if needed, to bolster shareholders' return on investment.

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[7] See MSFR Vol 2, 1-5-8(a)(12)(2019), at p. 11 (Emphasis added).
[8] See MSFR Vol 2 of 3, 1-5-8(a)(12)(2019), p. 2 of 13 (Emphasis added).

**Q: ARE THERE OTHER PROBLEMS WITH THE PLAN?**

A: Yes. The Company's plan is also structured to benefit its highly compensated senior level employees more than its rank and file employees, as shown in the chart below: [9]

| Grade Structure | | |
|---|---|---|
| **Salary Plan** | **Grade** | **Target %*** |
| SP20 | 1 | 5% |
| | 2 | 5% |
| | 3 | 5% |
| | 4 | 6% |
| | 5 | 8% |
| | 6 | 9% |
| | 7 | 10% |
| | 8 | 10% |
| | 9 | 15% |
| | 10 | 20% |
| | 11 | 25% |
| | 12 | 30% |
| | 13 | 35% |
| | 14 | 40% |
| | 15 | 45% |
| | 16 | 50% |
| | 17 | 55% |
| | 18 | 60% |
| | 19 | 80% |
| | 20 (CEO) | 135% |
| All Others | All | 5% |
| * As a percent of eligible earnings. | | |

According to the Company's plan, a participant's award opportunity is their target or maximum award percentage multiplied by their eligible earnings. As set forth in the chart above, the target percentages for employees in Grades 1-3 is only **5% of eligible earnings**, while the target percentage for Grade 20 (CEO) is **135% of eligible earnings**. This means that the decisionmakers (in the highest level positions) are afforded disproportionate

[9] The referenced chart is excerpted from MSFR Vol 2 of 3, 1-5-8(a)(12)(2019), p. 9 of 13.

incentives to maximize shareholder earnings, while employees at lower levels (those often dealing with customers and day to day operations) have limited incentive compensation opportunities under this top-heavy, financially-based, incentive plan.

**Q: IS THE 70% EPS METRIC THE ONLY FINANCIALLY-BASED PERFORMANCE MEASURE YOU FOUND IN AEP'S ANNUAL INCENTIVE COMPENSATION PLANS?**

A: No. AEP's annual incentive plans contain other financially-based performance measures ***in addition to*** the 70% EPS metric. AEP's annual incentive funding is tied to Operating Earnings per Share (70% weight), safety and compliance (10% weight) and strategic initiatives (20% weight). The "strategic initiatives" category contains a combination of operational and financially-based performance measures, as shown in the table below:[10]

| 2019 Strategic Initiatives | Weight | |
|---|---|---|
| **Cost Control** | | **4%** |
| Sustainable Efficiency Gains | 4% | |
| **Infrastructure Investment** | | **9%** |
| Transmission Infrastructure Investment | 4% | |
| Contracted Renewables Portfolio Growth | 2% | |
| Regulated Renewables | 2% | |
| Customer Targeted Regulated Renewables | 1% | |
| **Customer Experience and Quality of Service** | | **4%** |
| SAIDI | 1% | |
| Proactive Measures | 1% | |
| J.D. Power Residential Overall Customer Satisfaction Index | 1% | |
| Easy To Do Business With | 1% | |
| **Workforce of the Future and Culture** | | **3%** |
| Employee Culture Survey | 1% | |
| Diversity | 1% | |
| Future of Work | 1% | |
| **Total Strategic Initiative Weight** | | **20%** |

Of specific concern is the sub-category "Infrastructure Investment" which makes up 9%

[10] The referenced table is excerpted from MSFR Vol 2 of 3, 1-5-8(a)(12)(2019), p. 4 of 13.

of AEP's funding plan for 2019. 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.[11]

**<u>Transmission Infrastructure Investment (3% weight)</u>**

- Plant in Service (2% weight)
  - Maximum (200% payout) – $3.655B
  - Target (100% payout) – $3.519B
  - Threshold (0% payout) – $3.310B

This portion of the plan is clearly financially-based and designed to maximize shareholder earnings. If AEP's transmission infrastructure investment spending is below the threshold level of **$3.310 billion**, there is 0% payout for this metric. If AEP meets the transmission infrastructure target of **$3.519 billion**, the Plan is funded at 100% payout level, and if the maximum target of **$3.655 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 specific target spending levels. This metric may help increase shareholder earnings and employee bonuses, but it is not designed to protect ratepayers' interests. For this reason, the Commission could allocate 79% of the Plan to shareholders – based on (70%) EPS metric and (9%) infrastructure investment metric.

**Q: HOW MUCH OF THE "STRATEGIC INITIATIVES" CATEGORY IS RELATED TO CUSTOMER SERVICE PERFORMANCE MEASURES?**

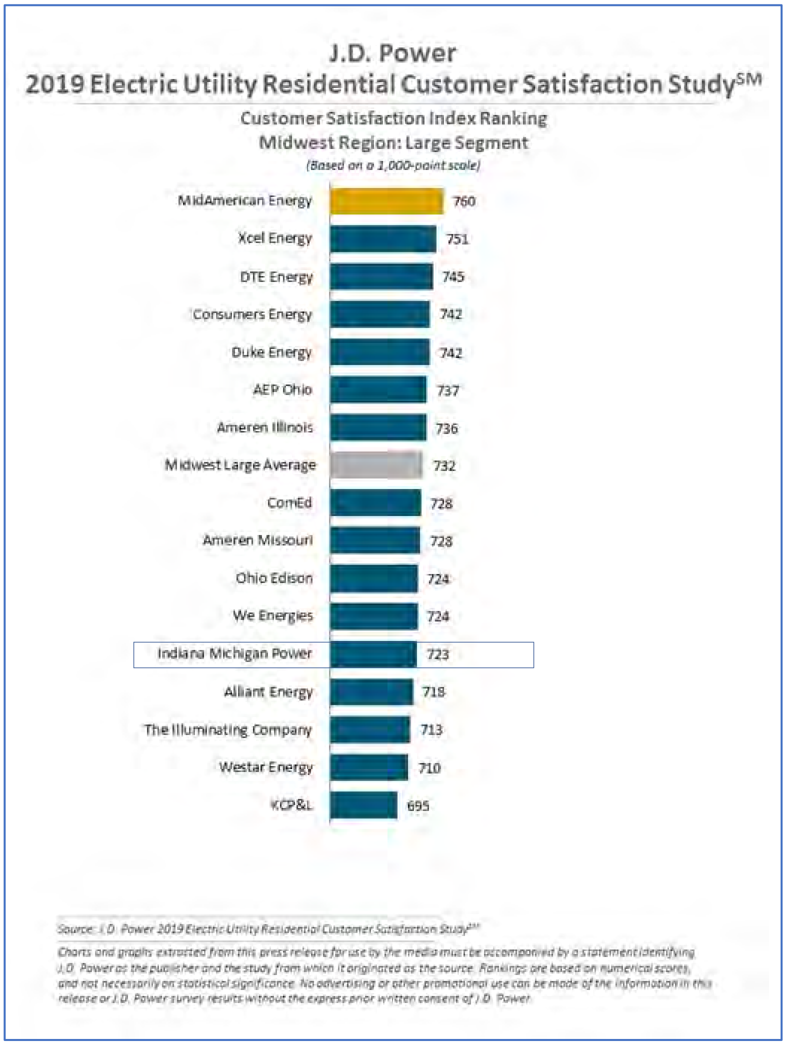
[11] The Transmission Infrastructure metric is excerpted from MSFR Vol 2 of 3, 1-5-8(a)(12)(2019), p. 4 of 13.

A: The Plan's strategic initiatives category allocates a total of **4%** to customer-related items: SAIDI (1%); Proactive Measures (1%); J.D. Power Residential Overall Customer Satisfaction Index (1%), and "Easy to do Business With" New service connection completion times (1%). These measures primarily benefit ratepayers, but together they only make up 4% of the plan. The remaining metrics represent a blend of attributes affecting savings, workforce quality, and employee culture, which benefit both shareholders and customers.

**Q: IS THERE EVIDENCE ABOUT HOW THE COMPANY IS PERFORMING ON CUSTOMER SERVICE MEASURES?**

A: The 2019 J.D. Power Residential Overall Customer Satisfaction Index (weighted at 1%), indicates that the Company ranks ***below average*** in customer satisfaction. As shown below, for 2019, Indiana Michigan Power ranked 13th out of the 16 companies in its segment, well below the Midwest Large Average:[12]

[12] Source: J.D. Power 2019 Electric Utility Residential Customer Satisfaction Study.




**Q: HOW HAS THIS COMMISSION ADDRESSED SHORT TERM INCENTIVE COMPENSATION PREVIOUSLY?**

A: The Commission has stated that it recognizes the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. The Commission's specific criteria are as follows:

> 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.[13]

Based upon these criteria, the Commission has allowed partial recovery of a utility's incentive compensation costs where it finds the plan "does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce."[14] The Commission has required that a portion of incentive plan costs be allocated to shareholders.

**Q: HAS THE COMMISSION PREVIOUSLY LIMITED RECOVERY OF INCENTIVE COMPENSATION COSTS IN ORDER TO ALLOCATE A PORTION OF THE COSTS TO SHAREHOLDERS?**

A: Yes. In Indiana-American Water Co., Inc., Cause No. 44022, the Commission imposed a 15% reduction, and a further reduction to eliminate incentive pay for a senior management position:

> Authorizing Petitioner to recover 100% of the AIP target level, would not allocate a sufficient amount of the incentive costs to shareholders. Therefore, we conclude that Petitioner shall recover 85% of the three-year average payout based on 358 employees with a further reduction to eliminate the incentive pay associated with the Senior Manager Business Development position.[15]

In the Indiana-American case, the Commission also denied recovery of the Company's long-term incentive plan ("LTIP") costs. In the next section of

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[13] See e.g., Southern Indiana Gas Company and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South"), Cause No. 43839, Final Order issued April 27, 2011, p. 42.
[14] Id.
[15] Indiana-American Water Company, Inc., Cause No. 44022, Order of the Commission issued June 6, 2012, p. 57.

testimony, I propose an adjustment to remove I&M's LTIP costs as well. However, the Commission's ***reasoning*** for disallowing the LTIP costs is important here:

> 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 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*.[16]

Thus, the Commission has indicated that shareholders should be allocated a portion of incentive plan costs. This also indicates the Commission takes into account ***how strongly a plan is tied to financial performance*** in determining whether the costs should be paid by shareholders rather than ratepayers.

**Q: IS YOUR RECOMMENDATION FOR THE TREATMENT OF ANNUAL INCENTIVE PLAN COSTS CONSISTENT WITH THE COMMISSION'S CRITERIA?**

A: Yes. For plans with both operational and financial performance goals, the Commission requires a ***sharing*** of costs between shareholders and ratepayers, and requires that "the incentive compensation plan does not result in excessive pay levels beyond what is

[16] Indiana-American Water Company, Inc., Cause No. 44022, Order of the Commission issued June 6, 2012, p. 57. (Emphasis added).

reasonably necessary to attract a talented workforce."[17] In this testimony, I provide evidence that ***recovery*** of the financially-based costs of I&M's annual incentive compensation plan is not "reasonably necessary to attract a talented workforce." Many utilities with which I&M competes for talent operate in jurisdictions that disallow recovery of financially-based incentives, or provide for a 50-50 sharing between shareholders and ratepayers. In particular, I present evidence regarding the regulatory treatment of AEP's annual incentive compensation plans with respect to its operating subsidiaries in Oklahoma and Texas.

**Q: ARE YOU FAMILIAR WITH THE REGULATORY TREATMENT OF AEP'S ANNUAL INCENTIVE COMPENSATION PLANS IN OKLAHOMA AND TEXAS?**

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. For more than 25 years, the Oklahoma commission has disallowed a portion (between 50% and 100%) of incentive compensation costs,[18] including disallowance of the financially-based annual incentive compensation costs of I&M's affiliate, PSO.[19] For

[17] Indiana-American Water Company, Inc., Cause No. 44022, Order of the Commission issued June 6, 2012, p. 57.
[18] See e.g., Oklahoma Natural Gas, Order in PUD 1991-1190, at page 145.
[19] *See* Oklahoma Cause Nos. PUD 200600285; PUD 200800144; PUD 201500208; and 201700151 (disallowing short term incentive costs tied to financial performance measures).

example, in PSO's 2008 rate case, PUD 200800144, the commission disallowed 50% of AEP/PSO's annual incentive plan.[20]

> The Commission finds that *although there is no evidence to conclude PSO's and AEPSC's overall salary levels are excessive, that the recommendation of the AG and Staff to **disallow 50%** of PSO's and AEPSC's incentive compensation should be adopted*. Incentive compensation benefits both shareholders and ratepayers equally, by encouraging the attainment of goals that provide good customer service and increase the earnings of the shareholders.

In PSO's 2015 rate case, Cause No. PUD 201500208, the commission's final order states:

> The ALJ adopts Staff and AG's recommendation that an adjustment be made to remove the portion of the Annual Incentive Program costs related to financial performance measures. In many jurisdictions, including Oklahoma, *the cost of incentive plans tied to financial performance measures generally are excluded for ratemaking purposes for several reasons*. *(See* Garrett Responsive Testimony, pp. *23-33).* The evidence in this case established that the Company's incentive compensation *is funded primarily based on the Company's financial performance (75% earnings per share)* . . . The result of the above disallowances reduces the recoverable expenses of PSO by . . . $4,369,947 for short term incentive expense, which is **50%** of the $8,739,895 requested by *PSO.*[21]

In PSO's 2017 rate case, the Commission again disallowed 50% of PSO's annual incentives plan costs.[22]

The Texas commission's policy is more stringent. It has a longstanding policy of disallowing 100% of annual incentives that are ***directly*** tied to financial performance measures, and in addition, disallows 50% of the remaining incentives if they are ***indirectly*** tied to financial performance through an earnings-per-share funding mechanism.[23] In

[20] See Final Order in Oklahoma Cause No. PUD 200800144, p.21.
[21] See Final Order No. 657877, Cause No. PUD 201500208, p. 161.
[22] See Final Order No. 672864, Cause No. PUD 201700151, p. 57.
[23] *See* SPS Docket No. 43695, Order on Rehearing at 5-6. *Also see*, SWEPCO Docket No. 46495, and Docket No 46449.

applying this approach to AEP's plan in the most recent Southwestern Electric Power Company (SWEPCO) case, in Docket No. 46449, the Texas commission made the following finding:

> **194.** The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because *financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services*.[24]

**Q: HOW DOES THE TREATMENT OF SHORT-TERM INCENTIVE COSTS IN THESE JURISDICTIONS COMPARE WITH OTHER JURISDICTIONS' TREATMENT OF INCENTIVE COMPENSATION?**

A: The policy of excluding a portion of short-term compensation costs is consistent with the majority of jurisdictions. The results of an Incentive Compensation Survey of the 24 Western States taken by the Garrett Group in 2007, and updated in 2009, 2011, 2015 and 2018, shows that a clear majority of the states surveyed follow the financial-performance rule, in which incentive payments associated with financial performance are excluded from rates. While some states disallow incentive pay using other criteria, and some states apply a sharing mechanism such as a 50%-50% allocation, none of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule. The results of the survey are set forth at Appendix *MG-3*. The table below provides a summary of the survey results:

[24] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Finding No. 194, Order on Rehearing at p. 34 (March 19, 2018). (Emphasis added).

| **Garrett Group, LLC<br>24 Western State Incentive Survey Results** | | | |
|---|---|---|---|
| **No Incentive Costs Allowed in Rates** | **Financial Performance Rule Followed** | **Other Sharing Approach** | **Incentives Not at Issue** |
| Hawaii | | | |
| | Arizona | | |
| | Arkansas | | |
| | California | | |
| | Idaho | | |
| | Kansas | | |
| | Louisiana | | |
| | Minnesota | | |
| | Missouri | | |
| | Nebraska | | |
| | Nevada | | |
| | New Mexico | | |
| | North Dakota | | |
| | Oklahoma | | |
| | Oregon | | |
| | South Dakota | | |
| | Texas | | |
| | Utah | | |
| | Washington | | |
| | Wyoming | | |
| | | Alaska[25] | |
| | | Colorado[26] | |
| | | | Iowa |
| | | | Montana |

As shown in the table above, and presented in more detail in Exhibit MG-3, many of the western states disallow a portion of incentive compensation costs where the incentive plans contain both financial and operational measures. Of those jurisdictions, several use a sharing approach to allocate costs between shareholders and ratepayers.

[25] Incentive compensation has not been an issue in the past, partly because most utilities in Alaska are municipalities and CO-OPs. In one recent case, however, the Commission approved incentives in rates, which may turn out to be an anomaly. See Exhibit MG-3.
[26] Colorado followed the financial performance rule in the past. In one recent case, however, the Commission approved another approach, which may turn out to be an anomaly. See Exhibit MG-3.

**Q: WHAT ARE SOME EXAMPLES OF COMMISSIONS THAT USE A *SHARING* APPROACH?**

A: In the survey of western states we identified several states that use a sharing approach, some of which include:

**Arkansas:** The Commission's policy is to disallow 50% of the short-term incentive plan costs in cases where the Company's incentive compensation plans are based in part on financial performance measures.[27]

**Arizona:** The Arizona commission on numerous occasions has shared the cost of annual incentive plans on a 50% - 50% split between shareholders and ratepayers.[28]

**Kansas:** The Kansas commission disallows 100% of plans based on financial measures and 50% for plans using a balance of financial and operational measures.[29]

**Oklahoma:** The Commission excludes incentive payments tied to financial performance. The Commission does not determine the precise portion of the annual plans tied to financial measures but instead excludes 50% of the annual plans.[30]

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[27] See Arkansas Public Service Commission, Docket No. 13-028-U, Order No. 21, p.54; and Docket No. 15-011-U. Order No. 10, p. 22, (citing prior dockets: Docket No. 04-121-U (Order No. 16 at 23-25); Docket No. 04-176-U (Order No. 6 at 38-40); Docket No. 06-101-U (Order No. 10 at 62-69, which order as related to incentive compensation was upheld on appeal at 104 Ark. App. 147, 289 S.W.3d 513 (2008)).

[28] *See* for example, APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

[29] *See* 2012 KCPL rate case, Cause No. 12-KCPE-764-RTS, in which short-term incentive costs were allocated 50% -50%.

[30] As discussed above, for electric utilities such as AEP, the Oklahoma commission has used a 50% sharing allocation for many years, in numerous cases. See e.g., OCC Final Order No. 672864, in AEP-PSO's last rate case, Cause No. PUD 201700151, p. 57. For gas utilities that use formula rates with an earnings-sharing mechanism, financial based incentives have been allowed because the increased earnings they generate are shared with customers.

**Q: WHAT IS THE TREATMENT OF INCENTIVES IN STATES SURROUNDING INDIANA?**

A: In addition to our survey of the western states, we surveyed three states in close proximity to Indiana: Illinois, Kentucky and Michigan. Although most regulatory commission's decisions are made on a case-by-case review of the evidence presented in each rate case, the general rule in these states is that financial-based incentives are not included in rates. The regulatory treatment in these states is set forth below:

**Illinois:** The general approach of the Illinois Commerce Commission has been that incentives based on financial goals are not allowed while those with operational goals are allowed in rates.[31] These criteria have been consistently applied by the Commission to short-term, long-term and executive incentive compensation. Long-term incentives are more often financially based and therefore more often disallowed. This treatment is the Commission's general practice, but it is also codified in the statute governing the formula rate plans for the state's two largest utilities (Ameren Illinois and Commonwealth Edison). Statute §220ILCS5/16-108.5c¶4(A) states:

> Recovery of incentive compensation expense that is based on the achievement of operational metrics, including metrics related to budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, and environmental compliance. Incentive compensation expense that is based on net income or an affiliate's earnings per share shall not be recoverable under the performance-based formula rate.

**Kentucky:** Any incentive compensation related to financial metrics is disallowed 100%. This treatment is applied to short-term, long-term and executive incentives. This treatment is not proscribed by regulation or statue, but has been the longstanding practice of the Commission. This treatment is set forth in the recent Kentucky American rate case 18-00358 (20190627 PSC Order 01, pp 41-44)[32]. In this case, 100% of the long-term incentives were disallowed while 50% of the short-term incentives were allowed. Even though the short-term plan had a funding mechanism based on earnings per share, the

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[31] See Commonwealth Edison, Docket No. 05-0597, pp. 95-97 (affirmed on appeal); North Shore Gas/Peoples Gas, Docket Nos. 09-0166 and 09-0167, (affirmed on appeal); and Illinois-American Water Co., Order No. 16-0093, p. 37.

[32] See also KPC 14-00396 20150622_PSC_ORDER (pp 24-26)

plan's performance measures were 50% financial and 50% non-financial. There have been no recent changes to this treatment.

**Michigan:** Incentive compensation based on financial metrics are excluded from rates. Incentives with non-financial metrics which have a demonstrable benefit to ratepayers are allowed in rates. This treatment is used for all incentive compensation and can produce a different result for short-term verses long-term and executive plans which are often stock-based plans which are not included in rates. There are no statues requiring this treatment, but it is the Commission's well-established policy based on consistent precedent. This treatment is set forth recently in Consumers Energy Company Electric Rate Case U-18322 and DTE Electric Rate Case U-20162.[33]

**Wisconsin:** Incentive compensation based on financial metrics are excluded from rates, as the commission has found that such plans do not reasonably provide benefits to ratepayers when tied to financial metrics.[34] In the Wisconsin Public Service 2013 rate case, the commission stated:

> The Commission is not persuaded it should change its practice of excluding incentive compensation from revenue requirements of the major investor-owned utilities in Wisconsin. WPSC has not demonstrated that the plans provide substantial ratepayer benefit with enough quantified permanent savings to ratepayers to warrant inclusion of the costs in revenue requirement. With the majority of executive incentive performance measures still tied to meeting earnings per share criteria, and the non-executive incentive performance measures that weigh heavily on measures tied to the shareholders benefit, <u>the Commission finds it is reasonable to exclude all incentive compensation costs from the revenue requirement</u>.[35]

**Q: IN YOUR EXPERIENCE, WHEN REGULATORS EXCLUDE THE PORTION OF A UTILITY'S INCENTIVE PLAN TIED TO FINANCIAL PERFORMANCE MEASURES, DOES THE UTILITY STOP OFFERING INCENTIVE COMPENSATION TO HELP ACHIEVE ITS FINANCIAL GOALS?**

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[33] In the U-20162 Order, the Commission cites Staff's Initial Brief (pp67-68) in which Staff lists 11 prior cases in which the Commission disallowed financially-based incentive compensation which does not benefit ratepayers.

[34] See Northern States Power Co., Docket 4220-UR-123, issued December 21, 2017, p. 16.

[35] Wisconsin Public Service, Docket 6690-UR-122, issued December 18, 2013, p. 24. Emphasis added.

No. Even though regulators generally disallow incentive compensation tied to financial performance for ratemaking purposes, utilities continue to include financial performance as a key component of their plans. In my opinion, utilities continue to tie incentive payments to financial performance because by doing so they achieve the primary objective of the incentive plans: to increase corporate earnings and, thereby, earnings per share (EPS). However, since the utility retains the increased earnings these plans help achieve, payments for these plans should be made from a portion of the increased earnings. These plans need not be subsidized by ratepayers. Recovery of plan costs through rates ***is not necessary to attract a talented workforce*** because the Company has other means of cost recovery—through the increased earnings generated by the plan.

**Q: WHAT IS THE GENERAL RATIONALE FOR EXCLUDING INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE?**

A: In most jurisdictions, the cost of incentive plans which are tied to financial performance measures are excluded for ratemaking purposes. When the costs associated with these plans are excluded, the ***primary*** rationale is that financially-based incentives benefit shareholders more than they do ratepayers. Other rationale used by the regulators is generally based on one or more of the following reasons:

**(1) Payment is uncertain.** Often, payment of incentive compensation is conditioned upon meeting some predetermined financial goal such as achieving a certain increase in earnings, reaching a targeted stock price or meeting budget objectives. If the predetermined goals are not met, the incentive payment is not made, or payment is made at some lesser amount. Therefore, one cannot know from year to year what the level of the payment may be or whether the payment will be made at all. It is generally considered inappropriate to set rates to recover a tentative level of expense.[36]

**(2) Many of the factors that significantly impact earnings are outside the control of most company employees and have limited value to customers.** For example, an unusually hot summer can easily trigger an incentive payment based on company earnings for an electric utility, as a cold winter can for a gas utility. Obviously, weather conditions are outside the control of utility employees and customers receive no benefit from the higher utility bills that result from an unusually hot or cold weather. Similarly, company earnings may increase, thus triggering incentive payments, as a result of customer growth, which commonly occurs without significant influence from company personnel. In fairness, since shareholders enjoy the benefits of customer growth between rate cases, shareholders should also bear the cost of any incentive payments such growth may trigger. Finally, utility earnings may increase substantially if the utility is able to successfully argue for a higher ROE in a rate case proceeding. Utility efforts to maximize ROE in a rate proceeding, however, have little to do with improving overall employee performance across the company. If utility employees gear their efforts toward securing an *unreasonably* high ROE in a rate proceeding, the incentive mechanism actually would work to the detriment of the utility customers.

**(3) Earnings-based incentive plans can discourage conservation.** When incentive payments are based on earnings, employees may not support conservation programs designed to reduce usage if they perceive these programs could adversely impact incentive payment levels. To the extent that earnings-based incentive plans discourage conservation and demand-side management programs, these plans do not serve the public interest. The growing focus on energy efficiency at both the national and state level renders this point especially important.

**(4) The utility and its stockholders assume none of the financial risks associated with incentive payments.** Ratepayers assume the risk that the utility will instead retain the amounts collected through rates for incentive payments whenever targeted increases are not reached. Employees assume the risk that the incentive payments will not be made in a given year. The utility and its stockholders, however, assume no risk associated with these payments. Instead, the company's only responsibility is to decide who gets the money, the stockholders or the employees.[37]

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[36] PSO's experience with its 2008 rate case proceeding, in Oklahoma PUD 2008-00144, is a good example of this problem. In 2009, AEP's below target EPS reduced the funding available for incentive compensation payments by 76.9%. Although in the Company's 2008 rate case, the Commission had included more than $4 million in rates for incentives, the Company chose not to use all of that money to pay incentives but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

[37] Id.

**(5) Incentive payments based on financial performance measures should be made out of increased earnings.** Whatever the targets or goals may be that trigger an incentive payment, when the plan is based in whole or in part on financial performance measures the company always obtains a financial benefit from achieving these objectives. This financial benefit should provide ample funds from which to make the payment. If not, the incentive plan was poorly conceived in the first place. As such, employees should be compensated out of the increased earnings, and not through rates.

**(6) Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition.** When utilities are allowed to embed amounts for incentive payments in rates, that money is available to the utility not only to pay the incentive payment when financial performance goals are met but also to supplement earnings in those years when the company does not perform well. In those years when financial performance measures are met, the increased earnings of the company provide ample additional funds from which to make the incentive payments to employees, and the incentive payment amount embedded in rates is not needed. In those years when financial performance measures are not met and the incentive payments are not made, the amount embedded in rates for incentive payments acts as a financial hedge to shelter the poor financial performance of the company.

**Q: UTILITIES OFTEN ASSERT THAT INCENTIVE PLANS SHOULD BE INCLUDED IN RATES BECAUSE THEY ARE PART OF A TOTAL COMPENSATION PACKAGE AND ARE COMPARABLE WITH THE COMPENSATION PAID BY OTHER UTILITIES. DO YOU AGREE?**

A: No. The rationale typically given for including incentive pay in rates is that incentive pay should be included in rates because it is needed to attract and retain qualified personnel. However, the argument is problematic. First, it misses the point. The question for regulators is not about what the <u>company</u> should pay; the question for regulators is what <u>ratepayers</u> should pay. The utility is free to offer whatever compensation package it deems appropriate to offer its employees, but most regulatory commissions agree that ratepayers should not pay the costs of plans designed to increase corporate earnings. Also, because incentive pay related to financial performance is generally disallowed, most of the utilities that compete with for talent generally do not recover all of their incentive compensation in rates. Therefore, a utility is not put at a competitive disadvantage when its incentive pay is similarly adjusted.

The other common problem with the Company's "total compensation package" argument is that when an incentive payment is based on achieving financial performance goals there should be a financial benefit to the company that comes from 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.

**Q: UTILITIES ALSO CLAIM INCENTIVE COMPENSATION COSTS 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 attracting for talent to provide safe and reliable service. The problem with this assertion is that it is not actually true. 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.[38] 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.[39] Likewise, many state-run electric systems also provide electric service without the use of short-term incentives,[40] as do some federally-owned utilities.[41] So, it is inaccurate to say that incentives are ***necessary*** for the provision of electric service.

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, particularly when incentive pay is tied to the financial performance.

**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:

[38] See e.g., Oklahoma Docket No. PUD 2018-00140, OG&E response to OIEC 9-8.
[39] Id.
[40] Id.
[41] Id.

> [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. <u>*NSPW's management is not prohibited from paying a portion of its overall 2018 employee compensation in the form of incentives*</u>. However, the amount of payroll expense authorized for recovery is limited to what the Commission has determined to be reasonable in this case.

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

A: The Company's plan is ***strongly tied*** to financial performance measures which include: an EPS trigger, a 70% EPS performance metric, and an additional 9% metric that incentivizes capital investment ***spending*** targets. Less than 30% of the plan's metrics relate to safety, customer satisfaction and reliability. Moreover, although the Company claims it has achieved satisfactory performance in operational categories, there is objective evidence that the Company has not performed well in either reliability or customer satisfaction.[42] Based on these factors, ***it would be reasonable for the Commission to disallow 70%,*** or more, of the annual incentive plan costs.

Although a 70% disallowance would be justified, I am recommending instead that the Commission adopt a ***50% - 50% sharing approach*** which allocates the 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

[42] See e.g., J.D. Power Customer Satisfaction survey, SAIDI and SAIFI scores.

ratepayers. My adjustment removes 50% of the annual incentive plan costs included in pro forma operating expense in the Indiana jurisdiction, and 50% of the capitalized annual incentive plan costs. The calculations supporting this adjustment are set forth at Schedule MG-11.

**<u>Adjustment to Remove 50% of Annual Incentive Costs (Indiana)</u>**

| | |
|---|---|
| Adjustment to Remove 50% of O&M Expense | $(8,381,609) |
| Adjustment to Reduce Related Payroll Taxes | $ (641,193) |
| Adjustment to Rate Base for Capitalized Incentives | $(2,913,125) |

## II. B. <u>LONG-TERM EXECUTIVE STOCK INCENTIVE PLAN</u>

**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 $9,879,360, which is $6,980,195 to the Indiana jurisdiction. [43]

**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.[44] The LTIP awards are composed of *performance units* and *restricted stock units* (RSUs). The performance units are granted based on two equally weighted performance measures: three-year total shareholder return, and three-year cumulative operating earnings per share (EPS) which is measured relative to a target set by AEP's

[43] See OUCC 9-13 Attachment 2019-2020 LTIP O&M.pdf.
[44] Id.

board of directors.[45]

**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 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

[45] Id.

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: The Commission has 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 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*.[46]

**Q: WHAT IS THE RATEMAKING TREATMENT OF AEP'S LONG TERM INCENTIVE COMPENSATION IN OKLAHOMA?**

A: The Oklahoma Corporation Commission ("OCC") disallows 100% of AEP's long-term

[46] Indiana-American Water Company, Inc., Cause No. 44022, Order of the Commission issued June 6, 2012, p. 57. (Emphasis added).

executive incentive plan costs. In PSO's 2006 and 2008 rate cases, the OCC found its long-term executive incentives are tied to the financial performance of AEP.[47] PSO's current long-term incentive plan is very similar to I&M's current plan and provides awards in the form of *performance units* and *restricted stock units* (RSUs). In PSO's 2015 rate case, PUD 201500208, the OCC disallowed 100% of the long-term incentive costs:

> With regard to long-term incentive compensation, the ALJ finds that the recommendation of the Staff, AG, and OIEC to disallow 100% of long-term incentive compensation is reasonable and should be adopted by the Commission. The *performance measures that result in the payment of long-term incentive compensation are financial goals that benefit shareholders*.[48]

In the Company's 2017 rate case,[49] the OCC disallowed 100% of PSO long-term plan costs, stating:

> 83. THE COMMISSION FURTHER FINDS that Mr. Farrar and Mr. Garrett both recommended adjustments to exclude 100 percent of the long-term incentive plan costs from rate recovery. *The long-term incentives are provided to highly compensated employees to align their interests and loyalty to shareholders*. These costs are not essential to serve the ratepayer and should be excluded from rate recovery. The performance measures used in the long-term incentive program are based on achieving financial goals that benefit shareholders and thus should not be borne by ratepayers. It *would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of shareholders first*.

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

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[47] See OCC Final Order in Cause No. PUD 200600285, at page 145, and OCC Order No. 564437 in Cause No. PUD 200800144 at page 21.
[48] See Final Order in Oklahoma Cause No. PUD 201500208, ALJ's Report, at page 162.
[49] See Final Order in Oklahoma Cause No. PUD 201700151, issued January 32, 2018, Attachment 1, p. 24. (Emphasis added)

A: The results of the Garrett Group Incentive Compensation Survey, discussed in the previous section of this testimony, show that 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 <u>not allowed</u> in most states.

According to the survey, 20 of the 24 western states tend to <u>exclude</u> all or virtually all long-term stock-based incentive pay, either through an outright ban on stock-based incentives or through applying the *financial performance* rule, which has the effect of excluding long-term earnings-based and stock-based awards. These states include Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington and Wyoming. In the other four states surveyed, Alaska, Iowa, Montana and Nebraska, the issue just has not been addressed.

**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, competes with other utilities for qualified executives, and the long-term incentive compensation plans of those other utilities are <u>not</u> 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, <u>*therefore, disallowance in this instance would not place NPC in a competitive disadvantage*</u>.[50] (Emphasis added).

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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[50] See Final Order in Docket 08-12002 at paragraph 549.

**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.[51] *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.[52] Likewise, *state-run electric systems* provide electric service without the use of long-term incentives,[53] as do *federally-owned utilities*.[54] 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

[51] See Oklahoma Cause No. PUD PUD 201800140, OG&E response to OIEC 9-8 by Michael Halloran, Senior Partner at Mercer (US) Inc., a firm specializing in employee compensation issues.
[52] Id.
[53] Id.
[54] Id.

operating expense in the Indiana jurisdiction and 100% of the capitalized long-term incentives. The calculations supporting this adjustment are set forth at Schedule MG-12.

**<u>Adjustment to Remove 100% of Long-Term Incentive Costs (Indiana)</u>**

| | |
|---|---|
| Adjustment to Remove 100% of O&M Expense | $(6,980,198) |
| Adjustment to Rate Base for Capitalized Long-Term Incentives | $(1,939,053) |

## II. C. <u>NON-QUALIFIED SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS</u>

**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 $260,000 for 2014, $265,000 for 2015, $270,000 for 2016, $275,000 for 2017 and $280,000 for 2018. 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 $98,614 of non-qualified plan costs in its in pro forma operating expense for ratemaking purposes in the Company's application.[55]

**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.

[55] *See* MSFR 1-5-8(A)(13) Projected, line 3, Vol. 2., p. 77.

**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. 40443, the Commission stated:

> 227. SWEPCO's non-qualified executive retirement benefits in the amount of $191,007 *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*.[56]

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*.[57]

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[56] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 40443, Findings of Fact No. 227 Order on Rehearing at 40 (March 6, 2014) (Emphasis added).
[57] See *Application of Southwestern Electric Power Co., for Authority to Change Rates*, Docket No. 46449, Findings of Fact Nos. 202-204, Order on Rehearing at 34 (March 19, 2018) (Emphasis added).

In Oklahoma, the OCC has consistently disallowed 100% of AEP-PSO's supplemental retirement pay.[58] In PSO's 2008 rate case, Cause No. PUD 200800144, the OCC stated:

> The Commission finds that the SERP expenses do not provide a benefit to the ratepayers of PSO and therefore adopts the recommendation of the AG and OIEC to deny recovery of these costs from PSO's ratepayers.

In PSO's 2017 rate case, Cause No. PUD 201700151, the Commission continued its longstanding policy of disallowing PSO's supplemental retirement plan costs.

> **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.

**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-13.

**Adjustment to Remove Supplemental Retirement Plan Expense $(98,614)**

[58] In every rate case since 2006, the OCC has disallowed 100% of AEP-PSO's SERP expense. *See* Cause No. PUD 200600285; Cause No. PUD 200800144, Cause No. PUD 201500208; and Cause No. PUD 201700151.

## II. D. EMPLOYEE BENEFIT ADJUSTMENTS

**Q: PLEASE DISCUSS THE COMPANY'S PROJECTED BENEFITS EXPENSE.**

A: The Company's benefits expense includes an employee savings plan, pension plans, group insurance coverage, postretirement benefits, and other costs. The projected test year employee benefits expense totals $39.5 million,[59] which is a $23.2 million increase over the 2018 benefits expense of $16.2 million.[60] I&M's proposes to more than double pensions and benefits expenses in a 2-year period, which is not practicable or reasonable.

**Q: WHAT ARE THE MAJOR COMPONENTS THAT CONTRIBUTE TO THIS PROJECTED INCREASE?**

A: I&M projects that its retirement savings plan contributions will increase by nearly $1 million[61] despite a modest change in payroll costs. It also proposes to increase pension expense by $4.7 million,[62] employee medical insurance by $6.2 million,[63] and the postretirement benefits to increase from a negative $11.7 million to a positive $1.7 million.[64]

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[59] See MSFR 1-5-8(a)(13) Projected.
[60] See MSFR 1-5-8(a)(13)(A)~(C) Historic.
[61] See MSFR 1-5-8(a)(13), $7.675 million projected compared to $6.710 million historic.
[62] See MSFR 1-5-8(a)(13), $7.675 million projected compared to $6.710 million historic.
[63] See MSFR 1-5-8(a)(13), $26.983 million projected compared to $20.779 million historic.
[64] See MSFR 1-5-8(a)(13)(A)~(C) Historic and MSFR 1-5-8(a)(13) Projected.

a. **Pension and OPEB Increases are Overstated**

**Q: WHAT CAUSED THE PENSION AND OPEB EXPENSES TO INCREASE SO DRAMATICALLY?**

A: I&M did not include the return on benefit plan assets in its calculations, which is a necessary adjustment that would reduce these expenses significantly.

**Q: DID YOU DETERMINE WHETHER THE RETURNS ON THE PENSION AND OPEB PLAN ASSET CONTINUE TO SUBSTANTIALLY REDUCE THESE COSTS?**

A: Yes. I reviewed the June 30, 2019 SEC 10-Q report filed by American Electric Power. This report reveals that the expected return on I&M's pension asset increased from $17.8 million for the first six months of 2018 to $18.4 million for the first six months of 2019. The expected return on I&M's OPEB assets decreased from $6.2 million to $5.7 million over the same comparative period.[65] The point is that there are significant positive returns on both funds.

**Q: HOW DOES THE RETURN ON THE PENSION AND OPEB FUND AFFECT I&M'S BENEFITS EXPENSE?**

A: Under generally accepted accounting principles, the earnings from the pension and OPEB fund assets are not capitalized, so the earnings from those funds reduce expenses on a dollar for dollar basis.

[65] See the American Electric Power Co. Inc. SEC Form 10-Q, June 30, 2019, page 154.

**Q: HOW WOULD INCLUDING THE RETURN ON FUND ASSETS CHANGE THE PROJECTED INCREASE?**

A: Including the return on fund assets would virtually eliminate the projected increases.

**Q: WHAT DO YOU RECOMMEND?**

A: I recommend that the 2018 expense levels be retained for the 2020 test year for both for pension and OPEB costs.

**b. <u>Medical Cost Increases are Overstated</u>**

**Q: WHAT DID THE COMPANY REQUEST WITH RESPECT TO FUTURE MEDICAL COSTS.**

A: The Company's forecasted test year includes $27.0 million for employee medical costs. This is an increase of $6.2 million over the test year level of $20.8 million. This represents an increase of 30% for the 24-month forecast period, or 15% annually.

**Q: IS A 15% ANNUAL INCREASE IN FORECASTED HEALTH CARE COSTS REASONABLE?**

A: No. Willis Towers Watson provides annual information concerning health care cost estimates. In its 2018 survey, the firm reported that healthcare costs increased by 4.7% in

2018 and are expected to increase by about 5% in 2019.[66] These annual approximate 5% increases are considerably less than the annual 15% increases projected by AEP.

**Q: WHAT IS THE YOUR RECOMMENDED FORECAST OF THE COMPANY'S 2020 MEDICAL EXPENSE?**

A: I recommend an annual 5% increase be applied to both the employee medical expenses. This is consistent with the market, which is the standard that AEP should be held to through regulation. This rate results in a total increase to the medical and dental insurance expenses of 10.25% over the two-year period. I also recommend the same 5% increase for dental costs, for the same reasons.

**Q: IS A 5% ANNUAL INCREASE IN PROJECTED MEDICAL AND DENTAL COSTS A REASONABLE AMOUNT?**

A: Yes. This is what companies in the competitive markets are expecting to achieve on average. From a ratemaking perspective, and especially in a situation where a forecasted test year is being used, the Company should be expected to contain future medical costs.

**Q: WHAT DO YOU RECOMMEND FOR THE OTHER EMPLOYEE BENEFIT EXPENSES?**

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[66] See Willis Towers Watson 23rd Annual Best Practices in Health Care Employer Survey at page 8, attached as Appendix MG-2. See https://www.willistowerswatson.com/-/media/WTW/Insights/2018/10/wtw-23rd-annual-best-practices-in-health-care-employer-survey-executive-summary.pdf.

A: I recommend that the remaining employee benefit expenses be included at the 2018 level. There is no basis for I&M to remove the returns on the pension and OPEB plan assets, and the remaining expenses are driven by employee levels which changed negligibly from the 2,199 average for 2018[67] to the 2,173 projected for 2020.[68]

**Q: WHAT IS THE AMOUNT OF YOUR ADJUSTMENT TO I&M'S EMPLOYEE BENEFIT EXPENSES?**

A: The adjustment to limit the increase in employee benefit expenses to a 5% annual increase for medical and dental insurance reduces the employee benefit expenses by $15,496,003 for the Indiana jurisdiction portion as found on Schedule MG-14.

**Q: DOES YOUR ADJUSTMENT LEAVE THE COMPANY WITH A REASONABLE OVERALL INCREASE IN EMPLOYEE BENEFITS?**

A: Yes. As shown on Schedule MG-14, OUCC proposes a Pension and Benefit expense level of $17.694M. This is $1.498M above the actual 2018 level of $16.196M (without SERP). This is an overall increase of 9.2% for the 2-year period 2018 through 2020, or 4.6% annually.

[67] See OUCC 9-29 Attachment 1 – 2014-2018 Payroll.xlsx.
[68] See MSFR: 1-5-8(a)(9) Projected.

## II. E. VEGETATION MANAGEMENT ADJUSTMENT

**Q: PLEASE DESCRIBE I&M'S VEGETATION MANAGEMENT PLAN.**

A: I&M witness David Isaacson describes the Company's vegetation management plan.[69] Mr. Isaacson indicates that the Company's overall reliability has been declining in recent years,[70] and that vegetation remains a principal cause of outages in its service territory.[71] In its last rate case, Cause No. 44967, the Company outlined a plan to increase its spending significantly to perform remedial maintenance over an initial four year period (2018-2021), and thereafter, to continue a regular four-year maintenance cycle.[72] In this case, the Company proposes to continue its planned remedial work[73] and forecasts Indiana jurisdictional vegetation management expense of **$16,241,025** for the test year ended December 31, 2020.[74] The Company contends that maintaining a higher level of spending on vegetation management it will "improve reliability and provide reasonable assurance that preventable vegetation-caused outages will be kept under control."[75]

**Q: HAS THE COMMISSION APPROVED I&M'S PROPOSED PLAN TO PERFORM REMEDIAL VEGETATION WORK AND A 4-YEAR MAINTENANCE CYCLE?**

A: No. Because the Company's last rate case, Docket No. 44967, was resolved through a settlement agreement, the Commission approved the parties' agreement to embed a spending level of $16,191,103 for vegetation management with no over/under deferral

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[69] See Direct Testimony of David S. Isaacson, pp. 4-15.
[70] See Direct Testimony of David S. Isaacson, p. 5, lines 18-21.
[71] Id. at p. 4, line 11.
[72] See Cause No. 44967, Direct Testimony of Thomas A. Kratt, p. 18, lines 15-22.
[73] See Direct Testimony of David S. Isaacson, p. 5, lines 18-21.
[74] Id., p. 14, Figure DSI-5.
[75] Id., p. 4, lines 16-18.

accounting.[76] However, the merits of the Company's plan to perform remedial vegetation work and to an ongoing 4-year maintenance cycle have not been substantively addressed or approved by the Commission.

**Q: HOW DOES THE COMPANY'S 2020 FORECASTED TEST YEAR LEVEL FOR VEGETATION MANAGEMENT COMPARE WITH ITS HISTORICAL DATA?**

A: The Company's $16.2 million test year forecast is much higher than its actual spending levels for most of the prior five years. Company witness David A. Lucas provided historical and projected cost data, noting that vegetation management costs were the primary driver in the Company's overall O&M spending increases in the test year.[77] The Company's expenditures for 2012-2018 are set forth below:

| **Indiana Jurisdiction Vegetation Management Costs[78]** | |
|---|---|
| 2014 | $ 10,201 |
| 2015 | $ 6,223 |
| 2016 | $ 9,829 |
| 2017 | $ 8,483 |
| 2018 | $ 17,452 |
| | |
| 5-Year Average (2012-2018) | $ 10,437 |

As shown in the chart above, the Company's vegetation management expenditures for 2012-2017 were sporadic, and generally much lower, than the forecasted test year level of $16.2 million. The fact that the Company spent $17.4 million in 2018 does not justify its request for ongoing recovery at an elevated level. The Company's expenditure for 2018

[76] See Cause No. 44967, Order of the Commission issued May 30, 2018, p. 11-12.
[77] See Direct Testimony of David A. Lucas, p. 12 and WP-DAL-1.
[78] Sources: For historical cost data 2014-2018, see WP-DAL-1.

was more than ***double*** its 2017 expenditure, and was 67% higher than the 5-year average of $10.438 million. The Company acknowledges that its expenditures for 2018-2021 are largely related to remedial work—in other words, the Company is attempting to catch up on deferred maintenance—work that should have been completed in prior years. The Company's forecasted 2020 test year level of $16.2 million also includes remedial work and represents a 55% increase over the 5-year average.

**Q: WHY ARE YOU CONCERNED THAT THE COMPANY SEEKS TO RECOVER FORECASTED COSTS ASSOCIATED WITH REMEDIAL MEASURES?**

A: The concern is twofold. First, the Company's plan seeks to recover, ***in an accelerated manner,*** the costs associated with many years of deferred maintenance. A 55% cost increase above the 5-year average places an undue burden on ratepayers. The Company has an obligation to maintain its system on an ongoing basis to provide safe and reliable service. It is not appropriate for the Company to neglect necessary maintenance for several years, while ensuring profitability targets are several years, and then seek recovery of inflated costs of performing remedial maintenance. This illustrates the concern I raised with respect to the Company's financially-based incentive compensation plan. Financially based plans that focus too heavily on achieving earnings targets incentivize employees to protect the Company's bottom line at the expense of reliability and customer service. During the years in question, 2012-2017, AEP met its annual EPS targets and funded employee incentive compensation plans, but did not always spend the amounts necessary to keep up with its vegetation management obligations. Moreover, the Company failed to spend the ***projected*** amounts from its last rate case.

**Q: PLEASE EXPLAIN.**

A: In the Company's last rate case, Cause No. 44967, the Company indicated that its ***projected*** vegetation management expenditure for 2017 would be $14.712 million[79] However, according in the schedules filed in this case, the Company's actual expenditure for 2017 was only $8.483 million,[80] a difference of $6.229 million that was diverted to the Company's bottom line rather than spent on what the Company represented was necessary vegetation management expense.

**Q: DID THE MICHIGAN COMMISSION RECENTLY RAISE SIMILAR CONCERNS REGARDING I&M'S VEGETATION MANAGEMENT PLAN?**

A: Yes. The Michigan Public Service commission addressed the Company's vegetation management plan in Case No. U-18370. In that case, I&M sought approval for its forecasted 2017 vegetation management spending level of $19.569 million;[81] however, the commission limited the Company's recovery to **$9.192** million, less than half the Company's requested amount. The commission was unwilling to approve the Company's request to dramatically increase its vegetation management recovery to essentially "catch up" on years of deferred maintenance. The commission expressed concerned that an

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[79] See Cause No. 44967, I&M Response to OUCC 27-01 Attachment_1.xls.
[80] See WP-DAL-1.
[81] See Michigan PSC Case No. U-18370, Order p. 43.

aggressive 4-year plan is not cost-beneficial given northern growing patterns. The Commission was also concerned that the Company might not actually ***spend*** the full amounts projected for line clearance projects. The commission stated:

> The ALJ recommended that the Commission adopt the Staff's proposed disallowance. In the ALJ's opinion, over the last ten years, *I&M's inconsistent spending demonstrates a lack of commitment to its vegetation management program*. The ALJ argued that, *had the "utility spent the amounts budgeted for annual vegetation management since its last rate case, . . . I&M's system would most likely be in better shape at present*." PFD, p. 64. Although the ALJ agreed that I&M could benefit from additional spending on this program, *without evidence that the company will actually spend funds on line clearance projects*, he found the steep increase in costs for the accelerated four-year program to be unreasonable at this time.[82]

> The Commission finds persuasive the ALJ's findings and recommendation. As noted by the Staff and the ALJ, over the last five years, the company has never spent more than $11 million annually on line clearing and, accordingly, is unlikely to spend the requested $19 million. And, as pointed out by the Staff, *the Commission has never approved a four-year vegetation management cycle for any other Michigan utility given the growing patterns of trees in this part of the country*. Therefore, ***until I&M shows that it consistently spends budgeted amounts for line clearing***, the Commission finds that the Staff's proposed amount of $9,192,679 for 2018 is sufficient to allow the company to continue its current trim cycle and to improve customer reliability.[83]

**Q: WHAT DO YOU RECOMMEND?**

A: I recommend that the O&M expense for vegetation management be normalized to a 5-year average of actual expenditures, which includes the higher level of expenditure for 2018.

**Q: WHAT IS THE IMPACT OF YOUR ADJUSTMENT?**

[82] See Michigan PSC Case No. U-18370, Order p. 43.
[83] Id., at p. 44 (Emphasis added).

**A:** The impact of this for the Indiana jurisdiction is set forth below and is shown at Schedule MG-15.

**Adjustment to Normalize Vegetation Management Expense $(5,803,400)**

## II. F. <u>RATE CASE EXPENSE AMORTIZATION</u>

**Q: WHAT IS THE COMPANY REQUESTING WITH RESPECT TO RATE CASE EXPENSE?**

A: The Company is proposing an adjustment of $776,941 for rate case expense, which is a 2-year amortization of the $1,553,883 total rate case expense.

**Q: DO YOU AGREE WITH THIS PROPOSAL?**

A: No. I have concerns with both the amount of rate case expense proposed and the Company's proposed amortization period.

**Q: WHAT ARE YOUR CONCERNS WITH THE AMOUNTS PROPOSED?**

A: The requested levels of rate case expense are high. The amount proposed for outside legal services is $1,170,000, which is about 75% of the total rate case budget. Because rate cases costs are generally driven by the costs of expert witnesses, it is unusual to see legal fees as such a high percentage of overall costs.

**Q: WHAT ARE THE OVERALL ESTIMATED COSTS FOR THE RATE CASE?**

A: The costs are set forth in the table below:

| | |
|---|---|
| Legal Fees | $1,170,000 |
| Witness Training | 124,250 |
| ROE Witness | 106,125 |
| Salvage Study | 65,002 |
| Decommissioning Study | 4,250 |
| Nuclear Decommissioning Study | 63,241 |
| Publication of Notice | 3,298 |
| Hearing Expense | 17,717 |
| Total | $1,553,883 |

**Q: WHY DO YOU SAY THE PROPOSED LEGAL FEES IN THIS CASE APPEAR DISPROPORTIONALLY HIGH?**

A: Based on personal experience, in several recent rate cases in which I am currently or was recently involved, other utilities spend far less, and/or seek to recover much lower levels of outside legal fees through rates. For example, AEP's subsidiaries, PSO and SWEPCO, both spend far less than I&M for legal fees in their rate cases. In PSO's last two rate cases in Oklahoma, the utility estimated $500,000 for legal fees.[84] Likewise, in SWEPCO's pending rate case in Arkansas, the utility estimates that it will spend $500,000 on legal costs.[85] The estimated legal costs in Indiana are more than double these levels.

Moreover, many utilities incur much smaller levels for outside counsel because they use internal lawyers to process the cases. For example, Nevada Power Company included ***no additional*** costs for legal fees in its last rate case, because it utilizes in-house legal counsel to process the case.[86] Similarly, Sierra Pacific, in its pending rate case, has requested not rate case recovery for outside legal counsel.[87] Likewise, Oklahoma Gas

[84] See Cause No. PUD 201700151, at WP H-12.2 and Cause No. PUD 201800097, at WP H-13.2.
[85] See Docket No. 19-008-U, at WP C-2-5.
[86] See Docket No. 17-06003 at Schedule I-CERT-19.2.
[87] See Docket No. 19-06002 at Schedule H-CERT-27.2.

and Electric Company ("OG&E") included only $50,000 for outside counsel in its pending rate case up to the hearing date, and the case subsequently settled.[88] OG&E, like Nevada Power and Sierra Pacific, uses in-house attorneys to process most of the rate case work. This is a much more cost-effective approach.

**Q: IS IT FAIR TO COMPARE LEGAL COSTS IN INDIANA TO LEGAL COSTS IN OKLAHOMA AND ARKANSAS?**

A: Yes. The Bureau of Labor Statistics reports that average salaries for attorneys in Indiana are very similar to the average salary levels in Oklahoma and Arkansas.[89]

**Q: WHAT DO YOU RECOMMEND?**

A: I recommend that the legal fees for the rate case be shared between ratepayers and shareholders. I recommend a 50/50 sharing of the legal fees that are actually incurred in this case up to the time a final order is issued.

**Q: WHAT DO YOU RECOMMEND WITH RESPECT TO THE AMORTIZATION OF THE RATE CASE COSTS?**

A: I recommend that the rate case costs be amortized over a three-year period.

**Q: HOW IS YOUR ADJUSTMENT CALCULATED?**

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[88] See Cause No. PUD 201800140 at WP H-13a.

[89] Bureau of Labor Statistics—May 2018 State Occupational Employment and Wage Estimates reports that the annual mean salary levels for lawyers in Indiana, Oklahoma and Arkansas are $113,360, $118,790 and $98,780 respectively.

A: My adjustment reduces the legal costs by 50% and changes the amortization period from two years to three years. These changes result in an adjustment of $453,980, as set forth at Schedule MG-8.

**II. G. <u>FACTORING EXPENSE</u>**

**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 2020 forecasted test year, the Company included $9,701 million in O&M for factoring expense, of which $7,825 is assigned to the Indiana jurisdiction based upon the receivables which the Company sells.[90]

**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 several years are set forth in the workpapers sponsored by I&M witness David A. Lucas.[91] To ascertain the reasonableness of the Company's forecasted test year factoring expense level, I compared it to the Company's actual factoring expense levels for 2016 through 2018. Based upon the

[90] See Direct Testimony of Jennifer C. Duncan, p. 14, and WP JCD-1, p. 11 of 15, Indiana Jurisdictional Separation Study Projected For the Test Year Ended December 31, 2020.
[91] See WP-DAL-1

Company's actual experience its 3-year average factoring expense is $7,632 million. Because the forecasted 2020 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. This adjustment results in a decrease of $1,668,892 to the Indiana jurisdictional O&M expense, and is set forth on Schedule MG-16.

**Q: DO YOU BELIEVE THAT FACTORING EXPENSE WILL BE LOWER THAN THE COMPANY'S FORECASTED AMOUNT DURING THE RATE EFFECTIVE PERIOD?**

A: Yes. I disagree with the Company's request for an increase in factoring expense because all indications are that interest rates will be lower in the rate effective period. Although interest rates were increasing during the period from 2015 through 2018, the Federal Reserve recently cut interest rates by 25 basis points on July 31, 2019. Moreover, it indicates that this may be the first in a series of rate cuts. Thus, the Company's requested increase would cause factoring expense to be overstated, and a more appropriate level is the 3-year average that I recommend.

## 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. Hiss recommendations result in new proposed depreciation rates for several of the Company's accounts. The impacts of his recommendations on the revenue requirement are set forth in Schedule MG-18.

## 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-1.

## 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:

| Issue | OUCC Witness | Testimony Page Ref. | Proposed Adjustment |
|---|---|---|---|
| **Rate Base** | | | (Total Company) |
| DSI Enhancement | C. Armstrong | p. 9 | $(13,315,000) |
| Coal Combustion Residuals | L. Aguilar | p. 28 | $(4,069,000) |
| Prepaid Pension Asset | M. Stull | p. 11 | $(89,244,007) |
| South Bend Solar Project | W. Blakley | | $(29,303,000) |
| AMI | A. Alvarez | p. 34 | $(14,167,000) |
| Distribution Management Plan | A. Alvarez | p. 34 | $(75,121,330) |
| Major Projects Adjustment | A. Alvarez | p. 34 | $(32,570,000) |
| Rockport Unit 2 Turbine Replacement | A. Alvarez | p. 34 | $(1,323,000) |
| Cook Nuclear Decommission Study | M. Eckert | p. 7 | $(9,993,095) |
| Decommission Study/Rate Case Cost | M. Eckert | p. 14 | $(776,941) |
| | | | |
| **Capital Structure Adjustments** | | | |
| Prepaid Pension Asset ADIT | M. Stull | p. 23 | $14,758,278 |
| | | | |
| **Revenue Adjustments** | | | |
| Customer Count Adjustment | G. Watkins | p. 49 | $3,758,305 |
| NITS Charges Moved to Base Rates | M. Gahimer | p. 21 | $(233,040,725) |
| | | | |
| **O&M Adjustments** | | | |
| NITS Charges Moved to Base Rates | M. Gahimer | p. 21 | $233,040,725 |
| DSI Enhancement | C. Armstrong | p. 9 | $(124,668) |
| Consumables | W. Blakley | p.6 | $(7,955,332) |
| PEV Pilot Program | L. Aguilar | p.28 | $(700,000) |
| Prepaid Pension Expense | M. Stull | p.25 | $1,909,822 |
| Economic Development Programs | J. Haselden | p. 3 | $(1,750,000) |
| AMI | A. Alvarez | p. 34 | $(2,410,722) |
| Major Storm Expense | A. Alvarez | p. 34 | $(1,574,529) |
| Distribution Management Plan | A. Alvarez | p. 34 | $(1,009,608) |
| Cook Decommission Study Amort. | M. Eckert | p. 12 | $(713,792) |
| Cook DTF Expense | M. Eckert | p. 17 | $(10,000,000) |
| Capacity Performance Insurance | M. Gahimer | p. 26 | $(1,513,220) |
| | | | |

# VI. OUCC REVENUE REQUIREMENT SUMMARY

**INDIANA MICHIGAN POWER COMPANY**
Adjustment Summary
For the Test Year Ending December 31, 2020

| Line | Description | Ref. | Witness | Rate Base | Pre-Tax ROR | Rate Increase |
|---|---|---|---|---|---|---|
| 1 | Requested Amounts | | | $ 4,946,962,201 | | $ 172,004,651 |
| 2 | Rate Base Adjustments | | | | | |
| 3 | Capitalized Short-Term Incentives | Sch. MG-11 | M. Garrett | $ (2,913,125) | 7.337721% | $ (213,757) |
| 4 | Capitalized Long-Term Incentives | Sch. MG-12 | M. Garrett | (1,939,053) | 7.337721% | (142,282) |
| 5 | DSI Project Costs | Sch. MG-9 | Armstrong | (9,407,627) | 7.337721% | (690,305) |
| 6 | Coal Combustion Residuals | | Aguilar | (2,874,926) | 7.337721% | (210,954) |
| 7 | Prepaid Pensions | | Stull | (64,018,690) | 7.337721% | (4,697,513) |
| 8 | South Bend Solar | | Blakley | (20,703,845) | 7.337721% | (1,519,190) |
| 9 | AMI | | Alvarez | (14,167,000) | 7.337721% | (1,039,535) |
| 10 | Distribution Management Plan | | Alvarez | (75,121,330) | 7.337721% | (5,512,193) |
| 11 | Distribution Major Projects | | Alvarez | (32,570,000) | 7.337721% | (2,389,896) |
| 12 | Rockport Unit 2 HP Turbine | | Alvarez | (934,757) | 7.337721% | (68,590) |
| 13 | Cook Nuclear Decommision Study | | Eckert | (7,060,556) | 7.337721% | (518,084) |
| 14 | Decommission Study/Rate Case | | Eckert | (548,943) | 7.337721% | (40,280) |
| 15 | Total Rate Base Adjustments | | | $ (232,259,851) | | $ (17,042,579) |
| 16 | Cost of Capital Adjustments | | | | | |
| 17 | Capital Structure | Sch. MG-20 | Garrett/Stull | $ 4,714,702,350 | 0.015830% | $ 746,350 |
| 18 | Return on Equity | 9.10% | D. Garrett | $ 4,714,702,350 | -0.719012% | (33,899,297) |
| 19 | Total Cost of Capital Adjustments | | | | | $ (33,152,947) |
| 20 | Operating Income Adjustments | | | | | |
| 21 | Short-Term Incentive Plans | Sch. MG-11 | M. Garrett | | | $ (9,022,802) |
| 22 | Long-Term Incentive Plans | Sch. MG-12 | M. Garrett | | | (6,980,198) |
| 23 | SERP | Sch. MG-13 | M. Garrett | | | (98,614) |
| 24 | Pensions and Benefits | Sch. MG-14 | M. Garrett | | | (15,496,003) |
| 25 | Vegetation Management | Sch. MG-15 | M. Garrett | | | (5,803,400) |
| 26 | Factoring | Sch. MG-16 | M. Garrett | | | (1,668,892) |
| 27 | Revenue - Customer Count | Sch MG-10 | Watkins | | | (3,758,305) |
| 28 | Uncollectible Accounts | Sch. MG-17 | M. Garrett | | | 7,990 |
| 29 | Utility Receipts Tax and Assessment | Sch. MG-17 | M. Garrett | | | 57,255 |
| 30 | Consumables | Sch. MG-10 | Blakley | | | (5,620,788) |
| 31 | DSI Project Costs | Sch. MG-10 | Armstrong | | | (88,083) |
| 32 | PEV Pilot | Sch. MG-10 | Aguilar | | | (700,000) |
| 33 | Econ. Dev. & Consumer Srvc. | Sch. MG-10 | Haselden | | | (1,236,451) |
| 34 | AMI | Sch. MG-10 | Alvarez | | | (2,410,722) |
| 35 | Major Storm Reserve | Sch. MG-10 | Alvarez | | | (1,574,529) |
| 36 | Distribution Management Plan | Sch. MG-10 | Alvarez | | | (1,009,608) |
| 37 | Cook Decommission Study | Sch. MG-10 | Eckert | | | (504,325) |
| 38 | Cook FTF Expense | Sch. MG-10 | Eckert | | | (7,065,435) |
| 39 | Pension Expense | Sch. MG-10 | Stull | | | 1,370,000 |
| 40 | Capacity Performance Insurance | Sch. MG-10 | Gahimer | | | (1,069,156) |
| 41 | Depreciation Adjustment | Sch. MG-18 | D. Garrett | | | (54,901,549) |
| 42 | Rate Case Expense | Sch. MG-8 | M. Garrett | | | (453,980) |
| 43 | Additional Uncollectible Accounts | Calc. | M. Garrett | | | (250,927) |
| 44 | Additional Utility Tax / Assessment | Calc. | M. Garrett | | | (1,798,075) |
| 45 | Total Adjustments to Operating Income | | | | | $ (120,076,595) |
| 46 | Total Adjustments | | | | | $ (170,272,121) |
| 47 | **Net Increase in Rates** | | | | | **$ 1,732,530** |

## 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, LLC – Regulatory Consulting Practice (1996 - Present)** Participates as a consultant and expert witness in electric utility, natural gas distribution company, and natural gas pipeline matters before regulatory agencies making recommendations related to cost-based rates. Reviews management decisions of regulated utility companies for reasonableness from a ratemaking perspective especially regarding the reasonableness of prices paid for natural gas supplies and transportation, coal supplies and transportation, purchased power and renewable energy projects. Participates in gas gathering, gas transportation, gas contract and royalty valuation disputes to determine pricing and damage calculations and to make recommendations concerning the reasonableness of charges to royalty and working interest owners and other interested parties. Participates in regulatory proceedings to restructure the electric and natural gas utility industries. 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. **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.

2. **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.

3. **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.

4. **Air Liquide Hydrogen Energy U.S., 2019 (Nevada), (704B Exit Application) –** Participating 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.

5. **Empire District Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800133)** – Participating 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.

6. **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.

7. **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.

8. **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.

9. **Oklahoma Gas and Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800140) –** Participating 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.

10. **Cascade Natural Gas, 2019 (Washington) (Docket No. 190210) –** 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.

11. **CenterPoint Energy Houston Electric, 2019 (Texas) (Docket No. 49421) –** Participating 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



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issues.

**12.** **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")[1] 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.

**13.** **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.

**14.** **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.

**15.** **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.

**16.** **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.

**17.** **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.

**18.** **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").

**19.** **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.

**20.** **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").

**21.** **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").

**22.** **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").

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[1] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.



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23. **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").

24. **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").

25. **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").

26. **Sierra Pacific Power Company (Nevada), 2018 (Docket No. 18-02011 and 18-02015)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers[2] before the Nevada PUC in SPPC's application related to the Tax Cuts and Jobs Act of 2017 ("TCJA").

27. **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").

28. **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").

29. **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.

30. **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.

31. **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.

32. **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.

33. **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 issues.

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



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34. **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.

35. **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.

36. **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 design issues.

37. **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.

38. **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.

39. **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.

40. **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.

41. **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.

42. **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.

43. **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.

44. **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.

45. **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



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testimony on various revenue requirement issues.

46. **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.

47. **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 Recovery Factor.

48. **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.

49. **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.

50. **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")[3] 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.

51. **Sierra Pacific Power Company (Nevada), 2016 (Docket No. 16-06006) –** Participated as an expert witness on behalf of the Northern Nevada Utility Customers[4] before the Nevada PUC in SPPC's general rate case proceeding. Sponsored testimony on various revenue requirement, depreciation, and rate design issues.

52. **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.

53. **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.

54. **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.

55. **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.

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[3] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.
[4] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.



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56. **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.

57. **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.

58. **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.

59. **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.

60. **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.

61. **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.

62. **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.

63. **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.

64. **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.

65. **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.

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[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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**66.** **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.

**67.** **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.

**68.** **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.

**69.** **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.

**70.** **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.

**71.** **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.

**72.** **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.

**73.** **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.

**74.** **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.

**75.** **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.

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

77. **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.

78. **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.

79. **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.

80. **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

81. **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.

82. **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.

83. **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.

84. **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.

85. **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.

86. **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.

87. **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.

**88.** **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.

**89.** **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.

**90.** **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.

**91.** **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.

**92.** **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.

**93.** **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.

**94.** **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.

**95.** **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.

**96.** **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.

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

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



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98. **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.

99. **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.

100. **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.

101. **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.

102. **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.

103. **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.

104. **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.

105. **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.

106. **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.

107. **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.

108. **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.

109. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398) –** Participated as an expert



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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.

**110.** **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.

**111.** **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.

**112.** **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.

**113.** **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.

**114.** **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.

**115.** **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.

**116.** **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.

**117.** **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.

**118.** **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.

**119.** **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.

**120.** **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.



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121. **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.

122. **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.

123. **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.

124. **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.

125. **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.

126. **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.

127. **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.

128. **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.

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

130. **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.

131. **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.



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132. **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.

133. **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.

134. **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.

135. **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.

136. **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 an 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, it transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

137. **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.

138. **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.

139. **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 cost-of-service based rates.

140. **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.

141. **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.

142. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564) -** Participated as an expert



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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:

143. **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.

144. **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.

145. **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.

146. **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.

147. **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.

148. **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.

149. **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 business in California.

150. **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.

151. **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.

152. **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.

153. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455) –** Participated as an expert witness



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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.

154. **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.

155. **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.

156. **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.

157. **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.

158. **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.

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

160. **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.

161. **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.

162. **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.



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**163.** **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.

**164.** **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.

**165.** **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.

**166.** **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.

**167.** **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 (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.

**168.** **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.

**169.** **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.

**170.** **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.

**171.** **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.

**172.** **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



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purchasing practices.

**173.** **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.

**174.** **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.

**175.** **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.

**176.** **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.

**177.** **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.

**178.** **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.

**179.** **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.

**180.** **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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# Chapter 1 – Health benefit strategy: Focus on cost and affordability, prioritize clinical management and wellbeing

## Cost and risk

Although annual cost increases of employer-sponsored health care remain at low levels, cost trends after plan changes continue to be well above the rate of inflation. Employers are focused on minimizing cost increases and expect the trend to remain similar to the past 10 years.

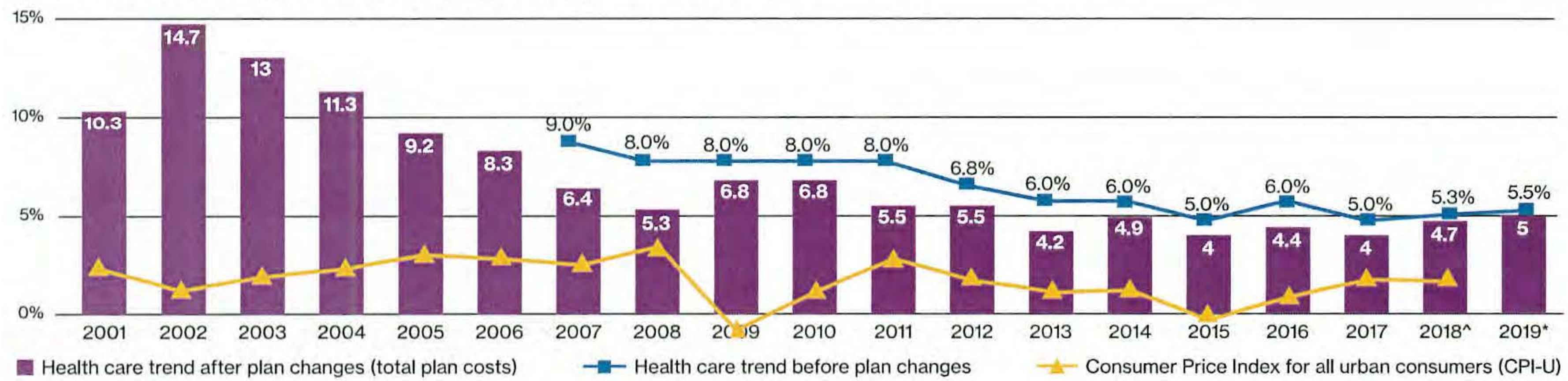
Respondents to our annual survey expect total health care costs (both employer and employee) to rise 5.0% in 2019 after plan design changes. According to our Financial Benchmark Survey results, the average cost of health care is $12,612 per employee per year (PEPY) in 2018; based on the expected increases, this will translate to $13,243 in 2019. For comparison, the general inflation rate for the first half of 2018 was 2.0%,[1] and many economic forecasts suggest this will persist throughout 2019.[2] Before plan changes, cost trends are expected to be 5.3% in 2018, which is up from 5.0% in 2017 *(Figure 2).*

Annual increases in the cost of health care, plus sustained cost shifting to employees over the years, continue to raise concerns about employee affordability – especially for lower-paid employees.

On average, employees contribute 24% of total premium costs in 2018. In paycheck deductions, this translates into an average annual employee contribution of $3,027 in 2018, which could rise to $3,178 per year in 2019 under current plan designs.

With their own PEPY costs rising, employers will continue to mitigate increases by managing their plan utilization and efficiency. Although many employers have moved to ABHP and even total replacement over recent years, one in five who moved to full replacement has reinstituted a plan without a high deductible.

Figure 2. **Health care costs before and after plan changes are well above the rate of inflation**




^Expected *Projected
Sample: Based on respondents with at least 1,000 employees

[1]Bureau of Labor Statistics figures for first half of 2018 average based on all urban consumers. https://data.bls.gov/timeseries/CUUR0000SA0L1E?output_view=pct_12mths
[2]OECD estimates. https://data.oecd.org/price/inflation-forecast.htm#indicator-chart



Appendix MG-2

**INDIANA MICHIGAN POWER COMPANY**
Adjustment Summary
For the Test Year Ending December 31, 2020

| Line | Description | Ref. | Witness | Rate Base | Pre-Tax ROR | Rate Increase |
|---|---|---|---|---|---|---|
| 1 | Requested Amounts | | | $ 4,946,962,201 | | $ 172,004,651 |
| 2 | Rate Base Adjustments | | | | | |
| 3 | Capitalized Short-Term Incentives | Sch. MG-11 | M. Garrett | $ (2,913,125) | 7.337721% | $ (213,757) |
| 4 | Capitalized Long-Term Incentives | Sch. MG-12 | M. Garrett | (1,939,053) | 7.337721% | (142,282) |
| 5 | DSI Project Costs | Sch. MG-9 | Armstrong | (9,407,627) | 7.337721% | (690,305) |
| 6 | Coal Combustion Residuals | | Aguilar | (2,874,926) | 7.337721% | (210,954) |
| 7 | Prepaid Pensions | | Stull | (64,018,690) | 7.337721% | (4,697,513) |
| 8 | South Bend Solar | | Blakley | (20,703,845) | 7.337721% | (1,519,190) |
| 9 | AMI | | Alvarez | (14,167,000) | 7.337721% | (1,039,535) |
| 10 | Distribution Management Plan | | Alvarez | (75,121,330) | 7.337721% | (5,512,193) |
| 11 | Distribution Major Projects | | Alvarez | (32,570,000) | 7.337721% | (2,389,896) |
| 12 | Rockport Unit 2 HP Turbine | | Alvarez | (934,757) | 7.337721% | (68,590) |
| 13 | Cook Nuclear Decommision Study | | Eckert | (7,060,556) | 7.337721% | (518,084) |
| 14 | Decommission Study/Rate Case | | Eckert | (548,943) | 7.337721% | (40,280) |
| 15 | Total Rate Base Adjustments | | | $ (232,259,851) | | $ (17,042,579) |
| 16 | Cost of Capital Adjustments | | | | | |
| 17 | Capital Structure | Sch. MG-20 | Garrett/Stull | $ 4,714,702,350 | 0.015830% | $ 746,350 |
| 18 | Return on Equity | 9.10% | D. Garrett | $ 4,714,702,350 | -0.719012% | (33,899,297) |
| 19 | Total Cost of Capital Adjustments | | | | | $ (33,152,947) |
| 20 | Operating Income Adjustments | | | | | |
| 21 | Short-Term Incentive Plans | Sch. MG-11 | M. Garrett | | | $ (9,022,802) |
| 22 | Long-Term Incentive Plans | Sch. MG-12 | M. Garrett | | | (6,980,198) |
| 23 | SERP | Sch. MG-13 | M. Garrett | | | (98,614) |
| 24 | Pensions and Benefits | Sch. MG-14 | M. Garrett | | | (15,496,003) |
| 25 | Vegetation Management | Sch. MG-15 | M. Garrett | | | (5,803,400) |
| 26 | Factoring | Sch. MG-16 | M. Garrett | | | (1,668,892) |
| 27 | Revenue - Customer Count | Sch MG-10 | Watkins | | | (3,758,305) |
| 28 | Uncollectible Accounts | Sch. MG-17 | M. Garrett | | | 7,990 |
| 29 | Utility Receipts Tax and Assessment | Sch. MG-17 | M. Garrett | | | 57,255 |
| 30 | Consumables | Sch. MG-10 | Blakley | | | (5,620,788) |
| 31 | DSI Project Costs | Sch. MG-10 | Armstrong | | | (88,083) |
| 32 | PEV Pilot | Sch. MG-10 | Aguilar | | | (700,000) |
| 33 | Econ. Dev. & Consumer Srvc. | Sch. MG-10 | Haselden | | | (1,236,451) |
| 34 | AMI | Sch. MG-10 | Alvarez | | | (2,410,722) |
| 35 | Major Storm Reserve | Sch. MG-10 | Alvarez | | | (1,574,529) |
| 36 | Distribution Management Plan | Sch. MG-10 | Alvarez | | | (1,009,608) |
| 37 | Cook Decommission Study | Sch. MG-10 | Eckert | | | (504,325) |
| 38 | Cook FTF Expense | Sch. MG-10 | Eckert | | | (7,065,435) |
| 39 | Pension Expense | Sch. MG-10 | Stull | | | 1,370,000 |
| 40 | Capacity Performance Insurance | Sch. MG-10 | Gahimer | | | (1,069,156) |
| 41 | Depreciation Adjustment | Sch. MG-18 | D. Garrett | | | (54,901,549) |
| 42 | Rate Case Expense | Sch. MG-8 | M. Garrett | | | (453,980) |
| 43 | Additional Uncollectible Accounts | Calc. | M. Garrett | | | (250,927) |
| 44 | Additional Utility Tax / Assessment | Calc. | M. Garrett | | | (1,798,075) |
| 45 | Total Adjustments to Operating Income | | | | | $ (120,076,595) |
| 46 | Total Adjustments | | | | | $ (170,272,121) |
| 47 | **Net Increase in Rates** | | | | | **$ 1,732,530** |
| 48 | Move NITS Charges Rider to Base Rates | | M. Gahimer | | | 233,040,725 |
| 49 | Increase to Base Rates | | | | | $ 234,773,255 |

**INDIANA MICHIGAN POWER COMPANY**

Determination of Revenue Increase/(Decrease)
For the Test Year Ending December 31, 2020

| Line No. | Description | | Amounts per Petitioner at Present Rates [1/] | Amount Per OUCC |
|---|---|---|---|---|
| 1 | Recommended Rate Base | | $ 4,946,962,201 | $ 4,714,702,350 |
| 2 | Required Rate of Return | | 5.91% | 5.40% |
| 3 | | | | |
| 4 | Net Operating Income Required | | $ 292,488,835 | $ 254,425,585 |
| 5 | Net Operating Income at Present Rates | | 168,915,989 | 256,213,031 |
| 6 | | | | |
| 7 | Net Income Surplus/(Deficiency) | | $ (123,572,846) | $ 1,787,446 |
| 8 | Revenue Multiplier 2/ | | 1.3596000 | 1.3596000 |
| 9 | | | | |
| 10 | Base Rate Revenue Increase | | $ 168,009,641 | $ (2,430,212) |
| 11 | Remove Transmission Owner Costs, Revenues | | 3,909,218 | 3,909,218 |
| 12 | | | | |
| 13 | Total Base Rate Revenue Increase | | $ 171,918,859 | $ 1,479,006 |
| 14 | | | | |
| 15 | Less: Current Revenue for Ongoing Riders | | (221,393,319) | (221,393,319) |
| 16 | | | | |
| 17 | Plus: Proposed Rider Revenue | | $ 221,646,844 | $ 221,646,844 |
| 18 | | | | |
| 19 | Total Rate Change Before Phase-In Credit | | $ 172,172,384 | **$ 1,732,531** |
| 20 | | | | |
| 21 | | | | |
| 22 | **<u>Verification</u>** | | | |
| 23 | Revenue Increase/(Decrease) | | $ 168,009,641 | $ (2,430,212) |
| 24 | Less: IURC Fee | 0.1202% | 201,955 | (2,921) |
| 25 | Bad Debt | 0.2126% | 357,188 | (5,167) |
| 26 | | | | |
| 27 | State Taxable Income | | $ 167,450,499 | $ (2,422,124) |
| 28 | | | | |
| 29 | State Income Tax | 5.2562% | 8,801,533 | (125,527) |
| 30 | Indiana Utility Receipts Tax | 1.4000% | 2,347,134 | (33,951) |
| 31 | | | | |
| 32 | Federal Taxable Income | | $ 156,301,832 | $ (2,262,646) |
| 33 | | | | |
| 34 | Federal Income Tax | 21.0000% | 32,823,385 | (475,156) |
| 35 | | | | |
| 36 | Net Income Surplus/(Deficiency) | | $ (123,478,447) | $ 1,787,490 |

**INDIANA MICHIGAN POWER COMPANY**

Summary of Operating Income
For the Test Year Ending December 31, 2020

| 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/ | $ 1,497,742,135 | $ 3,758,305 | $ 1,501,500,440 | $ (2,430,212) | $ 1,499,070,228 |
| 2 | | | | | | | |
| 3 | Operating Expenses | | | | | | |
| 4 | Operation and Maintenance | | $ 941,420,625 | $ (58,783,803) | $ 882,636,822 | $ (2,921) | $ 882,633,901 |
| 5 | Depreciation & Amortization | | 323,793,566 | (54,901,549) | 268,892,017 | | 268,892,017 |
| 6 | Taxes Other Than Income | | 83,988,863 | (583,938) | 83,404,925 | (33,951) | 83,370,974 |
| 7 | State Income Taxes | | (1,295,865) | 6,404,290 | 5,108,425 | (125,527) | 4,982,898 |
| 8 | Federal Income Taxes | | (19,081,043) | 24,326,262 | 5,245,219 | (475,156) | 4,770,063 |
| 9 | | | | | | | |
| 10 | Total Operating Expenses | | $ 1,328,826,146 | $ (83,538,737) | $ 1,245,287,409 | $ (637,555) | $ 1,244,649,854 |
| 11 | | | | | | | |
| 12 | Utility Operating Income | | $ 168,915,989 | $ 87,297,042 | $ 256,213,031 | $ (1,792,657) | $ 254,420,374 |
| 13 | | | | | | | |
| 14 | Rate Base | | $ 4,946,962,201 | | $ 4,714,702,350 | | $ 4,714,702,350 |
| 15 | | | | | | | |
| 16 | Rate of Return | | **3.41%** | | **5.43%** | | **5.40%** |

Note:

1/ Exhibit A-5, Page 1, Column (9).

**INDIANA MICHIGAN POWER COMPANY**

Summary of Rate Base
For the Test Year Ending December 31, 2020

| Line No. | Description | Indiana Jurisdictional Amount per Petitioner 1/ | OUCC Adjustments | Adjusted Per OUCC |
|---|---|---|---|---|
| 1 | Electric Plant in Service | $ 7,247,120,442 | $ (160,631,662) | $ 7,086,488,780 |
| 2 | Accumulated Depreciation & Amortization | (2,525,787,876) | - | (2,525,787,876) |
| 3 | Net Utility Plant in Service | 4,721,332,565 | (160,631,662) | 4,560,700,904 |
| 4 | Prepaid Pension Expense | $ 64,018,690 | $ (64,018,690) | $ 0 |
| 5 | Deferred Gain Rockport 2 Sale | (5,061,526) | - | (5,061,526) |
| 6 | Fuel Stock | 23,146,671 | - | 23,146,671 |
| 7 | Other Materials & Supplies | 116,811,112 | - | 116,811,112 |
| 8 | Regulatory Assets | 58,268,143 | (7,609,499) | 50,658,644 |
| 9 | Regulatory Liabilities | (2,588,975) | - | (2,588,975) |
| 10 | Allowance Inventory | 17,043,356 | | 17,043,356 |
| 11 | Deferred Income Taxes | (46,007,835) | - | (46,007,835) |
| 12 | Original Cost Rate Base | $ 4,946,962,201 | $ (232,259,851) | $ 4,714,702,350 |

**INDIANA MICHIGAN POWER COMPANY**

Summary of Adjustments to Rate Base
For the Test Year Ending December 31, 2020

| Line No. | Description | Source | Amount |
|---|---|---|---|
| 1 | Rate Base per Petitioner's Filing | Exhibit A-6, Page 1. | $ 4,946,962,201 |
| 2 | OUCC Adjustments | | |
| 3 | Capitalized STI | MG-11 | (2,913,125) |
| 4 | Capitalized LTI | MG-12 | (1,939,053) |
| 5 | DSI Project Costs | MG-9 | (9,407,627) |
| 6 | Coal Combustion Residuals | MG-9 | (2,874,926) |
| 7 | Remove Prepaid Pension Expense | MG-9 | (64,018,690) |
| 8 | South Bend Solar | MG-9 | (20,703,845) |
| 9 | AMI | MG-9 | (14,167,000) |
| 10 | Distribution Management Plan | MG-9 | (75,121,330) |
| 11 | Distribution Major Projects | MG-9 | (32,570,000) |
| 12 | Rockport Unit 2 HP Turbine | MG-9 | (934,757) |
| 13 | Cook Nuclear Decommission Study | MG-9 | (7,060,556) |
| 14 | Decommission Study/Rate Case | MG-9 | (548,943) |
| 15 | Total OUCC Adjustments | | $ (232,259,851) |
| 16 | OUCC Adjusted Rate Base | | $ 4,714,702,350 |

**INDIANA MICHIGAN POWER COMPANY**

Summary of Adjustments to Net Income
For the Test Year Ending December 31, 2020

| Line No. | 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 | $ 1,497,742,135 | $ 941,420,625 | $ 323,793,566 | | | $ 83,988,863 | $ (1,295,865) | $ (19,081,043) | $ 168,915,989 |
| 2 | | | | | | | $ 148,539,081 | | | |
| 3 | OUCC Adjustments | | | | | $ - | $ - | | | |
| 4 | STI Compensation | $ - | $ (8,381,609) | $ - | $ (641,193) | | | $ 474,257 | $ 1,795,195 | $ 6,753,351 |
| 5 | LTI Compensation | - | (6,980,198) | - | | | | 366,893 | 1,388,794 | 5,224,511 |
| 6 | Supplemental Pension | - | (98,614) | - | - | | | 5,183 | 19,620 | 73,810 |
| 7 | Pensions and Benefits | - | (15,496,003) | - | - | | | 814,501 | 3,083,115 | 11,598,386 |
| 8 | Vegetation Management | - | (5,803,400) | - | - | | | 305,038 | 1,154,656 | 4,343,706 |
| 9 | Factoring Expense | - | (1,668,892) | - | | | | 87,720 | 332,046 | 1,249,126 |
| 10 | Revenue | 3,758,305 | | | | 7,990 | 57,255 | 194,115 | 734,778 | 2,764,166 |
| 11 | Consumables | | (5,620,788) | | | | | 295,440 | 1,118,323 | 4,207,025 |
| 12 | DSI Project Costs | - | (88,083) | - | - | | | 4,630 | 17,525 | 65,928 |
| 13 | PEV Pilot | - | (700,000) | - | - | | | 36,793 | 139,273 | 523,933 |
| 14 | Econ. Dev. & Consumer Srvc. | - | (1,236,451) | - | - | | | 64,990 | 246,007 | 925,454 |
| 15 | AMI | - | (2,410,722) | - | | | | 126,712 | 479,642 | 1,804,368 |
| 16 | Major Storm Reserve | - | (1,574,529) | - | | | | 82,760 | 313,271 | 1,178,497 |
| 17 | Distribution Management Plan | - | (1,009,608) | - | | | | 53,067 | 200,874 | 755,667 |
| 18 | Cook Decom'n. Study Amort. | - | (504,325) | - | | | | 26,508 | 100,342 | 377,475 |
| 19 | Cook DTF Expense | | (7,065,435) | - | | | | 371,373 | 1,405,753 | 5,288,309 |
| 20 | Pension Expense | | 1,370,000 | | | | | (72,010) | (272,578) | (1,025,412) |
| 21 | Capacity Performance Ins. | | (1,069,156) | | | | | 56,197 | 212,721 | 800,237 |
| 22 | Depreciation Rate Adjustment | - | - | (54,901,549) | - | | | 2,885,735 | 10,923,321 | 41,092,493 |
| 23 | Rate Case Expense | | (453,980) | | | | | 23,862 | 90,325 | 339,793 |
| 24 | Interest Synchronization | - | - | - | - | | | 200,524 | 843,258 | (1,043,782) |
| 25 | Total OUCC Adjustments | $ 3,758,305 | $ (58,791,793) | $ (54,901,549) | $ (641,193) | $ 7,990 | 57,255 | $ 6,404,290 | $ 24,326,262 | $ 87,297,042 |
| 26 | OUCC Adjusted Net Income | $ 1,501,500,440 | $ 882,628,832 | $ 268,892,017 | $ (641,193) | $ 7,990 | $ 84,046,118 | $ 5,108,425 | $ 5,245,219 | $ 256,213,031 |

**INDIANA MICHIGAN POWER COMPANY**

Summary of Adjustments to Net Income
For the Test Year Ending December 31, 2020

| Line No. | Description | Ref. | Amount |
|---|---|---|---|
| 1 | Net Income per Petitioner (I&M Exhibit A-5, p.1) | | $ 168,915,989 |
| 2 | OUCC Adjustments | | |
| 3 | Short-Term Incentive Comp. Assoc. with Shareholders' Interest | MG-6 | 6,753,351 |
| 4 | Long-Term Incentive Comp. Assoc. with Shareholders' Interest | MG-6 | 5,224,511 |
| 5 | Supplemental Pension | MG-6 | 73,810 |
| 6 | Pensions and Benefits | MG-6 | 11,598,386 |
| 7 | Vegetation Management | MG-6 | 4,343,706 |
| 8 | Factoring Expense | MG-6 | 1,249,126 |
| 9 | Revenue - Customer Count | MG-6 | 2,764,166 |
| 10 | Consumables | MG-6 | 4,207,025 |
| 11 | DSI Project Costs | MG-6 | 65,928 |
| 12 | PEV Pilot | MG-6 | 523,933 |
| 13 | Econ. Dev. & Consumer Srvc. | MG-6 | 925,454 |
| 14 | AMI | MG-6 | 1,804,368 |
| 15 | Major Storm Reserve | MG-6 | 1,178,497 |
| 16 | Distribution Management Plan | MG-6 | 755,667 |
| 17 | Cook Decommission Study Amort. | MG-6 | 377,475 |
| 18 | Cook DTF Expense | MG-6 | 5,288,309 |
| 19 | Pension Expense | MG-6 | (1,025,412) |
| 20 | Capacity Performance Insurance | MG-6 | 800,237 |
| 21 | Depreciation Rate Adjustment | MG-6 | 41,092,493 |
| 22 | Rate Case Expense | MG-6 | 339,793 |
| 23 | Interest Synchronization | MG-6 | (1,043,782) |
| 24 | Total OUCC Adjustments | | $ 87,297,042 |
| 25 | Net Income Per OUCC | | $ 256,213,031 |

INDIANA MICHIGAN POWER COMPANY

Adjustment to
For the Test Year Ending December 31, 2020

| Line No. | Description | I&M Proposed Rate Case Expense (Indiana Direct) | Exclusion Percent | OUCC Proposed Rate Case Expense (Indiana Direct) | Adjustment |
|---|---|---|---|---|---|
| 1 | Legal Services | $ 1,170,000 | 50% | $ 585,000 | |
| 2 | CCA Training | 124,250 | | 124,250 | |
| 3 | Equity Return | 106,125 | | 106,125 | |
| 4 | Salvage Study | 65,002 | | 65,002 | |
| 5 | Decommissioning Testimony | 4,250 | | 4,250 | |
| 6 | Nuclear Decommissioning Study | 63,241 | | 63,241 | |
| 7 | Publication Notice | 3,298 | | 3,298 | |
| 8 | Witness Hearing Expense | 17,717 | | 17,717 | |
| 9 | | | | | |
| 10 | Total O&M | $ 1,553,883 | | $ 968,883 | |
| 11 | | | | | |
| 12 | Amortization Period (years) | 2 | | 3 | |
| 13 | | | | | |
| 14 | Annual Rate Case Expense | $ 776,941 | | $ 322,961 | **$ (453,980)** |

**INDIANA MICHIGAN POWER COMPANY**

Rate Base Adjustments Sponsored by Other Witnesses
For the Test Year Ending December 31, 2020

| Line No. | Description | OUCC Witness | Total Company Adjustment | Jurisdictional Factor [1/] | Indiana Jurisdictional Amount |
|---|---|---|---|---|---|
| 1 | DSI Project Costs | Armstrong | $ (13,315,000) | 70.6544% | $ (9,407,627) |
| 2 | Coal Combustion Residuals | Aguilar | (4,069,000) | 70.6544% | (2,874,926) |
| 3 | Prepaid Pension Asset | Stull | (89,244,007) | 71.7344% | (64,018,690) |
| 4 | South Bend Solar | Blakley | (29,303,000) | 70.6544% | (20,703,845) |
| 5 | AMI | Alvarez | (14,167,000) | Direct | (14,167,000) |
| 6 | Distribution Management Plan | Alvarez | (75,121,330) | Direct | (75,121,330) |
| 7 | Distribution Major Projects | Alvarez | (32,570,000) | Direct | (32,570,000) |
| 8 | Rockport Unit 2 HP Turbine | Alvarez | (1,323,000) | 70.6544% | (934,757) |
| 9 | Cook Nuclear Decommission Study | Eckert | (9,993,095) | 70.6544% | (7,060,556) |
| 10 | Decommission Study/Rate Case Cost | Eckert | (776,941) | 70.6544% | (548,943) |
| 11 | Total Rate Base Adjustments | | | | $ (227,407,673) |

Notes:
1/ Composite allocation factors

IURC Cause No. 45235
Schedule MG-10

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Operating Income Sponsored by Other OUCC Witnesses
For the Test Year Ending December 31, 2020

| Line No. | Description | OUCC Witness | Total Company Adjustment | Jurisdictional Factor [1/] | Indiana Jurisdictional Amount |
|---|---|---|---|---|---|
| 1 | Revenue - Customer Count | Watkins | $ 3,758,305 | Direct | $ 3,758,305 |
| 2 | DSI Project Costs | Armstrong | (124,668) | 70.6544% | (88,083) |
| 3 | PEV Pilot | Aguilar | (700,000) | Direct | (700,000) |
| 4 | Consumables | Blakley | (7,955,332) | 70.6544% | (5,620,788) |
| 5 | Pension Expense | Stull | 1,909,822 | 71.7344% | 1,370,000 |
| 6 | Econ. Dev. & Consumer Srvc. | Haselden | (1,750,000) | 70.6544% | (1,236,451) |
| 7 | AMI | Alvarez | (2,410,722) | Direct | (2,410,722) |
| 8 | Major Storm Reserve | Alvarez | (1,574,529) | Direct | (1,574,529) |
| 9 | Distribution Management Plan | Alvarez | (1,009,608) | Direct | (1,009,608) |
| 10 | Cook Decommission Study Amort. | Eckert | (713,792) | 70.6544% | (504,325) |
| 11 | Cook DTF Expense | Eckert | (10,000,000) | 70.6544% | (7,065,435) |
| 12 | Capacity Performance Insurance Rates | Gahimer | (1,513,220) | 70.6544% | (1,069,156) |
| 13 | Total Adjustments | | | | $ (19,121,014) |

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Remove Short-Term Incentive Compensation Expense Associated with Shareholders' Interest
For the Test Year Ending December 31, 2020

| Line No. | Description | I&M Short-Term Incentives | Composite Allocation Factors | Indiana Jurisdictional Amount |
|---|---|---|---|---|
| | Short-Term Incentive in O&M Expenses | | | |
| 1 | 2020 Short-Term Incentives - IMPC | $ 17,902,300 [1] | 70.6544% | $ 12,648,754 |
| 2 | | | | |
| 3 | 2020 Short-Term Incentives - AEPSC | 5,823,370 [1] | 70.6544% | 4,114,464 |
| 4 | | | | |
| 5 | Total Short-Term Incentives | $ 23,725,670 | | $ 16,763,218 |
| 6 | | | | |
| 7 | Financial Funded ICP Percentage | 50% [2] | | 50% |
| 8 | | | | |
| 9 | Financial Funded ICP | $ 11,862,835 | | $ 8,381,609 |
| 10 | | | | |
| 11 | Adjustment to Remove Long-Term Incentives | $ (11,862,835) | | $ (8,381,609) |
| 12 | | | | |
| 13 | FICA Tax at 7.65% | (907,507) | | (641,193) |
| 14 | | | | |
| 15 | Total Short-Term Incentive Adjustment | $ (12,770,342) | | $ (9,022,802) |
| 16 | | | | |
| 17 | Capitalized Incentives | | | |
| 18 | 2020 Capitalized Short-Term Incentives - IMPC | $ 3,602,710 [1] | 77.3819% | $ 2,787,845 |
| 19 | | | | |
| 20 | 2020 Capitalized Short-Term Incentives - AEPSC | 3,647,120 [1] | 71.9573% | 2,624,371 |
| 21 | | | | |
| 22 | Total Short-Term Incentives | $ 7,249,830 | | $ 5,412,215 |
| 23 | | | | |
| 24 | Financial Funded ICP Percentage | 50% | | 50% |
| 25 | | | | |
| 26 | Financial Funded ICP | $ 3,624,915 | | $ 2,706,108 |
| 27 | | | | |
| 28 | Adjustment to Remove Short-Term Incentives | $ (3,624,915) | | $ (2,706,108) |
| 29 | | | | |
| 30 | FICA Tax at 7.65% | (277,306) | | (207,017) |
| 31 | | | | |
| 32 | Total Short-Term Incentive Adjustment | $ (3,902,221) | | $ (2,913,125) |

Notes
1/ Response to OUCC DR 9-24 Attachment 2019-2020 ICP.pdf.
2/ Vol. 2, p. 24, 1-5-8(a)(12) (2018), p. 2 of 12; and Vol. 2 p. 36, 1-5-8(a)(12) (2019) p. 2 of 13

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Remove Long-Term Incentive Compensation Expense Associated with Shareholders' Interest
For the Test Year Ending December 31, 2020

| Line No. | Description | I&M Short-Term Incentives | | Composite Allocation Factors | Indiana Jurisdictional Amount |
|---|---|---|---|---|---|
| 1 | Long-Term Incentive in O&M Expenses | | | | |
| 2 | 2020 Long-Term Incentives - IMPC | $ 3,860,970 | 1/ | 70.6544% | $ 2,727,943 |
| 3 | 2020 Long-Term Incentives - AEPSC | 6,018,390 | 1/ | 70.6544% | 4,252,254 |
| 4 | Total Long-Term Incentives | $ 9,879,360 | | | $ 6,980,198 |
| 5 | Adjustment to Remove Long-Term Incentives for O&M Expenses | $ (9,879,360) | | | $ (6,980,198) |
| 6 | Capitalized Incentives | | | | |
| 7 | 2020 Capitalized Long-Term Incentives - IMPC | $ 726,570 | 2/ | 78.0851% | $ 567,343 |
| 8 | 2020 Capitalized Long-Term Incentives - AEPSC | 1,910,470 | 2/ | 71.7996% | 1,371,710 |
| 9 | Total Long-Term Incentives | $ 2,637,040 | | | $ 1,939,053 |
| 10 | Adjustment to Remove Long-Term Incentives from Rate Base | $ (2,637,040) | | | $ (1,939,053) |

Notes
1/ OUCC 9-13 Attachment 2019-2020 LTIP O&M.pdf
2/ OUCC 9-13 Attachment 2019-2020 LTIP Capitalized.pdf

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Remove Supplemental Pension Plan Expense
For the Test Year Ending December 31, 2020

| Line No. | Description | Amount |
|---|---|---|
| 1 | Non-Qualified Pension Plans in O&M Expenses | $138,000 |
| 2 | Adjustment to Remove Non-Qualified Pensions | ($138,000) |
| 3 | Composite Jurisdictional O&M Allocation Factor | 71.46% |
| 4 | Adjustment to Jurisdictional Expenses | ($98,614) |

Notes
1/ MSFR: 1-5-8(a)(13) Projected, line 3; Vol. II. Pg. 77
2/ 45235_IndMich_WP-Exhibit A-5 Net Operating Income Summary 04-04-19_051419.xlsx, cell I20, I21, H20, H21

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Employee Benefits
For the Test Year Ending December 31, 2020

| Line No. | Description | | Amount |
|---|---|---|---|
| 1 | 2018 Pensions and Benefits Expense | | $16,246,870 [1] |
| 2 | 2018 SERP | $82,412 [2] | |
| 3 | 2018 Pension O&M Factor | 0.613523704 [3] | |
| 4 | SERP O&M | $50,562 | ($50,562) |
| 5 | 2018 Pensions and Benefits Expense Excluding SERP | | $16,196,308 |
| 6 | | | |
| 7 | 2018 Group Medical Insurance | $20,778,517 [4] | |
| 8 | 2018 Group Dental Insurance | 1,035,179 [5] | |
| 9 | Total 2018 Group Medical & Dental | $21,813,696 | |
| 10 | Reasonable Increase Factor (1.05^2-1) | 0.1025 | |
| 11 | Reasonable Increase to Group Insurance | $2,235,904 | |
| 12 | Expense Factor | 0.670223969 [6] | |
| 13 | Reasonable Increase to Group Medical O&M | | 1,498,556 |
| 14 | Adjusted Pension and Benefit Expense | | $17,694,865 |
| 15 | | | |
| 16 | Requested Pension and Benefits Expense | $39,518,000 [7] | |
| 17 | Less Recommended SERP Adjustment | -138,000 [8] | |
| 18 | Adjusted Protected Pensions and Benefits | | 39,380,000 |
| 19 | | | |
| 20 | Adjustment to Pension and Benefits Expense | | ($21,685,135) |
| 21 | | | |
| 22 | Composite Jurisdictional O&M Allocation Factor | | 71.4591% [9] |
| 23 | | | |
| 24 | Adjustment to Jurisdictional Expenses | | ($15,496,003) |

**Notes:**

1/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, line 29; (Vol. II. Pg. 78)
2/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, line 5; (Vol. II. Pg. 78)
3/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, O&M line 8 divided by Total Cost sum of lines 4-6
4/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, line 10; (Vol. II. Pg. 78)
5/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, line 13; (Vol. II. Pg. 78)
6/ MSFR: 1-5-8(a)(13)(A)~(C) Historic, line 15 O&M divided by sum of lines 9-13, Total Cost
7/ MSFR: 1-5-8(a)(13) Projected, line 18; Vol. II. Pg. 77
8/ MSFR: 1-5-8(a)(13) Projected, line 3; Vol. II. Pg. 77
9/ 45235_IndMich_WP-Exhibit A-5 Net Operating Income Summary 04-04-19_051419.xlsx, cell I20, I21, H20, H21

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Normalize Vegetation Management Expense
For the Test Year Ending December 31, 2020

| Line No. | Description | Amount | |
|---|---|---|---|
| 1 | Forestry - Indiana, 2014 | $ 10,201,000 | [1] |
| 2 | Forestry - Indiana, 2015 | 6,223,000 | [1] |
| 3 | Forestry - Indiana, 2016 | 9,829,000 | [1] |
| 4 | Forestry - Indiana, 2017 | 8,483,000 | [1] |
| 5 | Forestry - Indiana, 2018 | 17,452,000 | [1] |
| 6 | Forestry - Indiana, Five Year Average 2016-2018 | $ 10,437,600 | |
| 7 | 2020 Projected Expense | 16,241,000 | [2] |
| 8 | Adjustment to Normalize Vegetation Management Expense | $ (5,803,400) | |

Notes

Notes:
1/ WP-DAL-1
2/ WP-JCD-1
3/ Based upon the percentage deemed attributable to operation earnings per MSFR 1-5-8(a)(12).
4/ Payroll Labor Factor per Attachment JMS-1, Page 17.

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Normalize Factoring Expense
For the Test Year Ending December 31, 2020

| Line No. | Description | Amount |
|---|---|---|
| 1 | 3-Year Average Factoring Expense | $ 7,632,000 |
| 2 | Test Year Factoring Expense | 9,701,000 [1] |
| 3 | Adjustment to O&M Expense | $ (2,069,000) |
| 4 | Jurisdictional Allocation Factor | 80.6618% |
| 5 | Adjustment to Indiana Jurisdictional O&M Expenses | $ (1,668,892) |

| Line No. | Description | 2016 | 2017 | 2018 | 3-YR AVG |
|---|---|---|---|---|---|
| 6 | Three Year Average Factoring Expense | | | | |
| 7 | Customer A/R Exp ($000) | $ 2,957 | $ 3,627 | $ 5,309 | $ 3,964 [1] |
| 8 | Fact Cust A/R Bad Debts | 4,120 | 3,040 | 3,843 | 3,668 [1] |
| 9 | Total Company | $ 7,077 | $ 6,667 | $ 9,152 | $ 7,632 |

| Line No. | Description | Amount |
|---|---|---|
| 10 | Jurisdictional Factor for Factoring Expense | |
| 11 | Direct Assign - Indiana | $ 7,825 [2] |
| 12 | Total | 9,701 |
| 13 | Jurisdictional Factor | 80.66% |

Notes
1/ WP-DAL-1
2/ ATT JCD-1 p.12

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Uncollectible Accounts and Revenue Taxes
For the Test Year Ending December 31, 2020

| Line No. | Description | Amount |
|---|---|---|
| 1 | Adjustments to Indiana Operating Revenue | $ 3,758,305 |
| 2 | Uncollectible Accounts Rate | 0.2126% |
| 3 | Adjustment to Uncollectible Accounts | $ 7,990 |

**INDIANA MICHIGAN POWER COMPANY**

Adjustment to Depreciation Expense
For the Test Year Ending December 31, 2020

| 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 | $ 1,188,869,866 | $ (20,432,939) | $ 1,168,436,927 | 6.654% | $ 77,747,209 | 70.6543% | $ 54,931,785 |
| 2 | Hydro | 54,413,336 | | 54,413,336 | 2.265% | 1,232,414 | 70.6543% | 870,754 |
| 3 | Nuclear | 3,602,398,404 | (1,376,190) | 3,601,022,214 | 3.473% | 125,069,150 | 69.9425% | 87,476,518 |
| 4 | Other | 66,252,744 | (29,303,000) | 36,949,744 | 4.168% | 1,539,889 | 70.6543% | 1,087,998 |
| 5 | Transmission | 1,746,064,348 | (826,455) | 1,745,237,893 | 2.338% | 40,807,653 | 70.6543% | 28,832,382 |
| 6 | Distribution | 2,688,722,100 | (124,469,008) [3/] | 2,564,253,092 | 2.606% [4/] | 66,816,160 | 79.9126% | 52,743,017 |
| 7 | General | 153,461,078 | - | 153,461,078 | 3.591% | 5,511,518 | 71.9071% | 3,963,171 |
| 8 | Totals | $ 9,500,181,876 | $ (176,407,591) | $ 9,323,774,285 | | $318,723,993 | | $ 229,905,625 |
| 9 | | | | | | | | |
| 10 | | | | | | 392,027,105 [5/] | | 284,807,174 [5/] |
| 11 | | | | | | | | |
| 12 | Adjustment to Depreciation Expense | | | | | $ (73,303,112) | | $ (54,901,549) |

Notes
1/ file 45235_IndMich_WP-NAH-12-19_051419.xlsx, tab WP-NAH-15 Detail Depre Adj, cells AF66-AF73
2/ Recommended by OUCC witness David Garrett.
3/ Indiana distribution plant adjustment
4/ Indiana distribution plant rate
5/ From WP-Exhibit A-5, tab Adjustments

**INDIANA MICHIGAN POWER COMPANY**

Interest Synchronization Adjustment
For the Test Year Ending December 31, 2020

| Line No. | Description | Amount | |
|---|---|---|---|
| | | $ - | |
| 1 | Rate Base per OUCC | $ 4,714,702,350 | 1/ |
| 2 | | | |
| 3 | Synchronized Interest Rate | 1.950% | 2/ |
| 4 | | | |
| 5 | Tax Deductible Interest per OUCC | $ 91,936,696 | |
| 6 | | | |
| 7 | Tax Deductible Interest per I&M | 95,971,067 | 3/ |
| 8 | | | |
| 9 | Synchronized Interest Increase to Taxable Income | $ 4,034,371 | |
| 10 | | | |
| 11 | Other Changes to Taxable Income | (219,381) | |
| 12 | | | |
| 13 | Increase in Taxable Income | $ 3,814,990 | |
| 14 | | | |
| 15 | State Income tax effect at 5.375% | $ 200,524 | |
| 16 | | | |
| 17 | Federal Income Tax Effect at 21% | $ 843,258 | |
| 18 | | | |
| 19 | Total Tax Savings | $ 1,043,782 | |

**INDIANA MICHIGAN POWER COMPANY**

OUCC Capital Structure and Rate of Return
For the Test Year Ending December 31, 2020

| Line No. | Description | Amount [1/] | Capitalization Ratio [1/] | Cost Rate [1/] | Weighted Cost Rate | Revenue Conversion Factor | Pre-Tax Rate of Return |
|---|---|---|---|---|---|---|---|
| | Prepaid Pension ADIT Adjustment | | | | | | |
| 1 | Long-Term Debt | $2,926,531,185 | 42.78% | 4.54% | 1.942230% | 1 | 1.942230% |
| 2 | Common Equity | 2,574,496,077 | 37.63% | 10.50% | 3.951602% | 1.3596 | 5.372598% |
| 3 | Customer Deposits | 37,972,608 | 0.56% | 2.00% | 0.011102% | 1 | 0.011102% |
| 4 | Accum. Def. FIT | 1,282,863,267 [3/] | 18.75% | 0.00% | 0.000000% | 1 | 0.000000% |
| 5 | Accum. Def. JDITC | 18,960,268 | 0.28% | 7.33% | 0.020316% | 1.3596 | 0.027622% |
| 6 | Total | $ 6,840,823,405 | 100.00% | | 5.925249% | | 7.353551% |
| 7 | | | | | | | |
| 8 | Adjustment to the Weighted Cost of Capital | | | | 0.012756% | | 0.015830% |
| 9 | | | | | | | |
| 10 | ROE Adjustment | | | | | | |
| 11 | Long-Term Debt | $2,926,531,185 | 42.78% | 4.54% | 1.9422% | 1 | 1.942212% |
| 12 | Common Equity | 2,574,496,077 | 37.63% | 9.10% [2/] | 3.4243% | 1.3596 | 4.655719% |
| 13 | Customer Deposits | 37,972,608 | 0.56% | 2.00% | 0.0112% | 1 | 0.011200% |
| 14 | Accum. Def. FIT | 1,282,863,267 | 18.75% | 0.00% | 0.0000% | 1 | 0.000000% |
| 15 | Accum. Def. JDITC | 18,960,268 | 0.28% | 6.67% | 0.0187% | 1.3596 | 0.025407% |
| 16 | Total | $ 6,840,823,405 | 100.00% | | 5.396429% | 1.2294312 | 6.634538% |
| 17 | | | | | | | |
| 18 | Adjustment to the Weighted Cost of Capital | | | | -0.5288% | | -0.719012% |
| 19 | AJDITC Cost Rate | | | | | | |
| 20 | Long-Term Debt | $ 2,926,531,185 | 53.20% | 4.54% | 2.42% | | |
| 21 | Common Equity | 2,574,496,077 | 46.80% | 9.10% [2/] | 4.26% | | |
| | | $ 5,501,027,262 | 100.00% | | 6.67% | | |
| 22 | Synchronized Interest Rate | | | | | | |
| 23 | Long-Term Debt | $ 2,926,531,185 | 42.78% | 4.54% | 1.94% | | |
| 24 | Common Equity | 2,574,496,077 | 37.63% | | 0.00% | | |
| 25 | Customer Deposits | 37,972,608 | 0.56% | 2.00% | 0.01% | | |
| 26 | Accum. Def. FIT | 1,282,863,267 | 18.75% | | 0.00% | | |
| | ` | 18,960,268 | 0.28% | | 0.00% | | |
| 27 | Total | $ 6,840,823,405 | 100.00% | | 1.95% | | |

Notes:
1/ Exhibit A-7, Page 3 of 4.
2/ Recommended by David Garrett on behalf of OUCC.
3/ Responsive Testimony of Margaret A. Stull, 23:6-10.

**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 | $2,926,531,185 | 42.69% | 4.54% | 1.938049% | 1 | 1.938049% |
| 2 | Common Equity | 2,574,496,077 | 37.55% | 10.50% | 3.943095% | 1.3596 | 5.361032% |
| 3 | Customer Deposits | 37,972,608 | 0.55% | 2.00% | 0.011078% | 1 | 0.011078% |
| 4 | Accum. Def. FIT | 1,297,621,545 | 18.93% | 0.00% | 0.000000% | 1 | 0.000000% |
| 5 | Accum. Def. JDITC | 18,960,268 | 0.28% | 7.33% | 0.020272% | 1.3596 | 0.027562% |
| 6 | Total | $ 6,855,581,683 | 100.00% | | 5.912494% | 1.2411 | 7.337721% |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |
| 11 | AJDITC Cost Rate | | | | | | |
| 12 | | | | | | | |
| 13 | Long-Term Debt | 2,926,531,185 | 53.20% | 4.54% | 2.42% | | |
| 14 | Common Equity | 2,574,496,077 | 46.80% | 10.50% | 4.91% | | |
| 15 | | 5,501,027,262 | 100.00% | | 7.33% | | |
| 16 | | | | | | | |
| 17 | | | | | | | |
| 18 | | | | | | | |
| 19 | Synchronized Interest Rate | | | | | | |
| 20 | | | | | | | |
| 21 | Long-Term Debt | $ 2,926,531,185 | 42.69% | 4.54% | 1.94% | | |
| 22 | Common Equity | 2,574,496,077 | 37.55% | | 0.00% | | |
| 23 | Customer Deposits | 37,972,608 | 0.55% | 2.00% | 0.01% | | |
| 24 | Accum. Def. FIT | 1,297,621,545 | 18.93% | | 0.00% | | |
| 25 | Accum. Def. JDITC | 18,960,268 | 0.28% | | 0.00% | | |
| 26 | Total | $ 6,855,581,683 | 100.00% | | 1.95% | | |

| 2/ Calculation of Cor | Per I&M Exhibit A-8 Tax Rates | | Per OUCC Tax Rates | |
|---|---|---|---|---|
| Operating Revenues | | **100.00%** | | **100.00%** |
| Less: Uncollectible Accounts Expense | | **0.2126%** | | **0.2126%** |
| Income Before Income Taxes | | **99.79%** | | **99.79%** |
| Less: Indiana | **1.4000%** | | **1.4000%** | |
| Public Utility Assessm | **0.1202%** | **1.5170%** | **0.1202%** | **1.5170%** |
| Base Subject to State Income Taxes | | **98.2704%** | | **98.2704%** |
| Less: State Inco | **5.2562%** | **5.1653%** | **5.2562%** | **5.1653%** |
| Income Before Federal Income Taxes | | **93.1051%** | | **93.1051%** |
| Less: Federal In | **21.00%** | **19.5521%** | **21.00%** | **19.5521%** |
| Operating Income Percentage | | **73.5530%** | | **73.5530%** |
| Gross Revenue Conversion Factor (100% / Li | | **1.3596** | | **1.3596** |
| Combined State Tax Rate | | **7.1772%** | | **7.1772%** |

**INDIANA MICHIGAN POWER COMPANY**
Adjustment Summary
For the Test Year Ending December 31, 2020

| Line | Description | Ref. | Witness | Rate Base | Pre-Tax ROR | Rate Increase |
|---|---|---|---|---|---|---|
| 1 | Requested Amounts | | | $ 4,946,962,201 | | $ 172,004,651 |
| 2 | Rate Base Adjustments | | | | | |
| 3 | Capitalized Short-Term Incentives | Sch. MG-11 | M. Garrett | $ (2,913,125) | 7.337721% | $ (213,757) |
| 4 | Capitalized Long-Term Incentives | Sch. MG-12 | M. Garrett | (1,939,053) | 7.337721% | (142,282) |
| 5 | DSI Project Costs | Sch. MG-9 | Armstrong | (9,407,627) | 7.337721% | (690,305) |
| 6 | Coal Combustion Residuals | | Aguilar | (2,874,926) | 7.337721% | (210,954) |
| 7 | Prepaid Pensions | | Stull | (64,018,690) | 7.337721% | (4,697,513) |
| 8 | South Bend Solar | | Blakley | (20,703,845) | 7.337721% | (1,519,190) |
| 9 | AMI | | Alvarez | (14,167,000) | 7.337721% | (1,039,535) |
| 10 | Distribution Management Plan | | Alvarez | (75,121,330) | 7.337721% | (5,512,193) |
| 11 | Distribution Major Projects | | Alvarez | (32,570,000) | 7.337721% | (2,389,896) |
| 12 | Rockport Unit 2 HP Turbine | | Alvarez | (934,757) | 7.337721% | (68,590) |
| 13 | Cook Nuclear Decommision Study | | Eckert | (7,060,556) | 7.337721% | (518,084) |
| 14 | Decommission Study/Rate Case | | Eckert | (548,943) | 7.337721% | (40,280) |
| 15 | Total Rate Base Adjustments | | | $ (232,259,851) | | $ (17,042,579) |
| 16 | Cost of Capital Adjustments | | | | | |
| 17 | Capital Structure | Sch. MG-20 | Garrett/Stull | $ 4,714,702,350 | 0.015830% | $ 746,350 |
| 18 | Return on Equity | 9.10% | D. Garrett | $ 4,714,702,350 | -0.719012% | (33,899,297) |
| 19 | Total Cost of Capital Adjustments | | | | | $ (33,152,947) |
| 20 | Operating Income Adjustments | | | | | |
| 21 | Short-Term Incentive Plans | Sch. MG-11 | M. Garrett | | | $ (9,022,802) |
| 22 | Long-Term Incentive Plans | Sch. MG-12 | M. Garrett | | | (6,980,198) |
| 23 | SERP | Sch. MG-13 | M. Garrett | | | (98,614) |
| 24 | Pensions and Benefits | Sch. MG-14 | M. Garrett | | | (15,496,003) |
| 25 | Vegetation Management | Sch. MG-15 | M. Garrett | | | (5,803,400) |
| 26 | Factoring | Sch. MG-16 | M. Garrett | | | (1,668,892) |
| 27 | Revenue - Customer Count | Sch MG-10 | Watkins | | | (3,758,305) |
| 28 | Uncollectible Accounts | Sch. MG-17 | M. Garrett | | | 7,990 |
| 29 | Utility Receipts Tax and Assessment | Sch. MG-17 | M. Garrett | | | 57,255 |
| 30 | Consumables | Sch. MG-10 | Blakley | | | (5,620,788) |
| 31 | DSI Project Costs | Sch. MG-10 | Armstrong | | | (88,083) |
| 32 | PEV Pilot | Sch. MG-10 | Aguilar | | | (700,000) |
| 33 | Econ. Dev. & Consumer Srvc. | Sch. MG-10 | Haselden | | | (1,236,451) |
| 34 | AMI | Sch. MG-10 | Alvarez | | | (2,410,722) |
| 35 | Major Storm Reserve | Sch. MG-10 | Alvarez | | | (1,574,529) |
| 36 | Distribution Management Plan | Sch. MG-10 | Alvarez | | | (1,009,608) |
| 37 | Cook Decommission Study | Sch. MG-10 | Eckert | | | (504,325) |
| 38 | Cook FTF Expense | Sch. MG-10 | Eckert | | | (7,065,435) |
| 39 | Pension Expense | Sch. MG-10 | Stull | | | 1,370,000 |
| 40 | Capacity Performance Insurance | Sch. MG-10 | Gahimer | | | (1,069,156) |
| 41 | Depreciation Adjustment | Sch. MG-18 | D. Garrett | | | (54,901,549) |
| 42 | Rate Case Expense | Sch. MG-8 | M. Garrett | | | (453,980) |
| 43 | Additional Uncollectible Accounts | Calc. | M. Garrett | | | (250,927) |
| 44 | Additional Utility Tax / Assessment | Calc. | M. Garrett | | | (1,798,075) |
| 45 | Total Adjustments to Operating Income | | | | | $ (120,076,595) |
| 46 | Total Adjustments | | | | | $ (170,272,121) |
| 47 | **Net Increase in Rates** | | | | | **$ 1,732,530** |
| 48 | Move NITS Charges Rider to Base Rates | | M. Gahimer | | | 233,040,725 |
| 49 | Increase to Base Rates | | | | | $ 234,773,255 |

# Garrett Group, LLC.
# Incentive Compensation Survey of the 24 Western States
# 2018 Update

## Results By State

Alaska 2011: (Regulatory Commission, Tyler Clark, Finance Manager, 907-276-6222) Incentive Compensation is not an issue in rate cases in Alaska. There is no relevant regulation or policy.

Alaska 2015: (Regulatory Commission, Tyler Clark, Chief Utility Financial Analyst, 907-276-6222) Incentive is not a contested issue yet in Alaska. There are no regulations, policies or cases addressing the issue.

**Alaska 2018:** (Regulatory Commission, Julie Vogler, Chief Utility Financial Analyst, 907-276-6222) The Commission in Alaska reviews requests to include incentive compensation in rates to determine if they are reasonable and if they benefit ratepayers. Short and long-term incentives receive the same treatment. The issue is handled on a case by case basis. In a recent Enstar Natural Gas case, U-16-066, the Commission allowed the Company's short and long-term incentive expense to be included in revenue requirement. The Final Order in U-16-066 (19), page 62, lines 6 through 14, states:

> The record establishes that the overall cost of ENSTAR's incentive compensation is reasonable in a regulatory context. The scope and mechanics of the STIP and LTIP are clearly defined and described. And incentive compensation payments under the STIP and LTIP have been consistent and are expected to recur at levels comparable to the test year. ENSTAR's incentive compensation plans benefit ratepayers by setting and holding employees to goals that directly relate to customer service and cost controls, and by attracting and retaining highly qualified employees to provide safe and reliable service. We find that inclusion of the incentive compensation amounts as an expense in ENSTAR's revenue requirement is reasonable.

The Enstar case is the first adjudicated case since the last survey results were provided in 2015, so there are no other recent orders that set forth a treatment of the issue.

Arizona: (Corporation Commission, Darron Carlson, 602-542-0834) Arizona deals with incentive compensation plans on a case by case basis. They generally do not allow the costs for these programs to be included in rate base. They have at times allowed 50% of the cost of a particularly good plan to be included in rates.

Arizona 2009: (Corporation Commission, Darron Carlson, 602-542-0834) Arizona deals with incentive compensation plans on a case by case basis. It first compares overall compensation to the state norm, then asks if the cost are prudent and reasonable. They lean toward disallowing programs which benefit only the shareholder even if total compensation is comparable to the state norm.

Arizona 2011: (Corporation Commission, Darron Carlson, 602-542-0834) Still examining case by case, the Arizona Staff's position is that if the company fails to demonstrate that an incentive compensation plan is tied to operational performance issues it is considered unnecessary for the provision of service. Staff feels shareholders should pay for plans tied to financial measures such as earning per share. Most cases settle here and there are no orders on point.

Arizona 2015: (Corporation Commission, Darron Carlson, Manager, Financial and Regulatory Analysis Section, Utility Division, 602-542-0834) Incentive programs are still considered case by case. Evaluation centers around the criteria of benefit to customers. This treatment tends to make long-term programs harder to justify, but the same criteria are used to evaluate all plans including those for executives. This treatment is set forth in the most recent Epcor Water rate case (Docket No. WS-01303A-14-0010). The current treatment represents a somewhat more liberalized approach compared to Arizona's former position of excluding all incentive compensation from rates.

Arizona 2017: A review of Commission decisions in cases since the 2001 Decision 64172 is provided in the testimony of staff witness Ralph C. Smith in Docket No. E-0134SA-16-0036 (pp.81-89). This review demonstrates that the Commission recognizes that financial goals primarily benefit the shareholder and operational goal can benefit the customer. The Commission accordingly shares the cost of short-term incentives equally between ratepayers and the shareholders. In Decision No. 71914 (September 30, 2010), in UNS Electric, Inc. rate case, Docket No. E-04204A-09-0206, the Commission stated at page 28:

> We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.

Arizona Incentive Compensation Treatment by Case

Short-Term Incentives*

| Year | Company | Docket/Decision Number | Lit./Stlmt. | Outcome |
|---|---|---|---|---|
| | | | | |
| 2001 | SWG | G-01551A-00-0309 / 64172 ( p. 13) | Litigated | 50:50 Sharing |
| 2007 | APS | E-013451-05-0816 / 69663 (p. 37) | Litigated | Allowed** |
| 2008 | APS | E-01345A-08-0172 | Settlement | 50:50 Sharing |
| 2011 | APS | E-01345A-11-0224 | Settlement | 50:50 Sharing |
| 2007 | UNS | G-04204A-06-0463 / 70011 (p. 27) | Litigated | 50:50 Sharing |

| | | | | |
|---|---|---|---|---|
| 2008 | UNS | E-04204A-06-0783 / 70360 ( p. 21) | Litigated | 50:50 Sharing |
| 2006 | SWG | G-01551A-04-0876 / 68487 (p. 18) | Litigated | 50:50 Sharing |
| 2008 | SWG | G-01551A-07-0504 / 70665 (p. 16) | Litigated | 50:50 Sharing |
| 2010 | UNS | G-04204A-08-0571 / 71623 (pp. 30-31) | Litigated | 50:50 Sharing |
| 2010 | UNS | E-04204A-09-0206 / 71914 (pp. 28-29) | Litigated | 50:50 Sharing |
| | | | | |

* See Staff witness Smith in APS 2016 Rate Case E-0134SA-16-0036 pp. 81-89.
** The Commission accepted Staff's position: "Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customer." (page 37)

**Arizona 2018:** (Corporation Commission, Darron Carlson, Public Utilities Analyst Manager, Revenue Requirements and Audits, 602-542-0834) There have been no changes to the treatment of incentives in Arizona. The issues is still dealt with on a case by case basis centered on benefit to the customer. The treatment is the same for short and long-term plans as well as executive incentives. There are no new orders setting forth the treatment.

Arkansas: (PSC, Alice Wright, 501-682-2051) In the current Entergy Arkansas Rate Case Docket No. 06-101-U, staff witness Jeff Hilton recommends excluding 50% of the portion of plans tied to financial performance, which means disallowing half of the executive's plan. See attached direct and surrebuttal testimony.

Arkansas 2009: (PSC, Jeff Hilton, Manager, Audit Section, General Staff, APSC 501-682-2051) The treatment of incentive compensation has changed recently in Arkansas. The traditional treatment had been to allow in rates those plans based on operational goals (which were seen as benefitting ratepayers), and sharing 50:50 between shareholders and ratepayers the costs of programs which included operational and financial goals (and thereby benefitting both ratepayers and shareholders). The current change is that now, executive plans which are based solely on increasing corporate stock value are seen as benefitting only the shareholders and are excluded from rates. A further refinement of Commission policy is to allow, for any given plan, 50% of the *portion* of that plan which has value for both ratepayers and shareholders. This new treatment is documented in the Entergy order 06-101-U, Order 10, and in the settlement adopted in the latest OG&E case 08-103-U. One reason for the change to exclude these executive plans was that while they were being subsidized by ratepayers they were growing astronomically.

Arkansas 2011: (PSC, Jeff Hilton, Manager, Audit Section, General Staff, APSC 501-682-2051) The Arkansas Commission has uniformly maintained its treatment based on the 2006 Entergy case (06-101-U) cited above. Long-term plans, typically based on stock price, are excluded from rates 100%. Short-term incentive plans are evaluated to determine if they are based on financial or operational measures. Operational-based plans are allowed. 50% of plans containing financial measures are disallowed. Any plans based solely on the discretion of the company are seen as having no direct benefit to ratepayers and are disallowed 100%. Settlements in recent cases have upheld this treatment.

Arkansas 2015: (PSC, Jeff Hilton, Director of Revenue Requirements, 501-682-2051) Commission rulings on Incentive Compensation have remained generally consistent, excluding 100% of long-term plans and 50% of the portion of short-term plans that are financially based. This treatment has been qualified in recent cases based on differing plan structures. In the most recent contested Entergy rate case (Docket No. 13-028-U), 50% of all short-term incentive compensation was excluded because the plans included a financially-based multiplier. The criteria of distinguishing between financial and operational measures that results in different treatment for short and long-term plans is used to evaluate all plans including those for executives. Arkansas' treatment of this issue is considered case by case and is based on prior Commission orders, not legislation. While the Commissioners' position has remained consistent, Staff's recommendation in the last several cases, including 13-028-U and two currently under review, has shifted. Staff has recently considered that any incentive compensation plan which they find is prudent and is necessary for the provision of utility service to ratepayers should be included in rates. Based on these criteria, Staff has recommended no disallowance in these three cases, a position which the Commission did not adopt in the 13-028-U Entergy case.

**Arkansas 2018**: (PSC, Jeff Hilton, Director of Revenue Requirements, 501-682-5185) The Arkansas Commission continues to follow the precedent of its previous orders and generally disallows 50% of financially based Short-term incentive plans and 100% of Long-term plans (which include the executive plans). There is some flexibility for considering a utility's particular situation on a case by case basis, but the two larger utilities in Arkansas, Entergy and CenterPoint, are both on formula rate plans and the 50%/100% disallowance treatment is incorporated in those FRPs, based on their most recent respective rate cases, 15-015-U and 15-098-U, in which the Commission specifically expressed this preference.[1]

California: (PUC, Pamela Thompson, Div. of Ratepayer Advocacy, 415-703-5581, Mark Pocta, 415-703-2871) In CPUC Decision 00-02-046 the Commission established that utilities could recover 50% of the regular employee's incentive compensation costs from rates. Mark Pocta says they advocate for some type of sharing arrangement and points out that PGE has a 50/50 arrangement for both executive and employee plans, while Southern California Edison passes 50% of its executive plan and all of its employee plan to ratepayers.

California 2009: (PUC, Mark Pocta, Division of Ratepayer Advocacy, 415-703-5581) In California, incentive compensation funding is always an issue and is typically litigated. In California's latest litigated rate case, Southern California Edison (Application #: 07-11-011, Decision #: 09-03-025) the DRA argued for disallowing of incentive compensation in rates citing vague performance measure and the fact that all the plans were, at least in part, based on the Company's financial performance. The Commission, however, decided that the non-executive plans (at Edison there are plans for all employees) and 50% of the short-term executive plans will be funded in rates, while only the long-term executive stock option plans will be disallowed. In 2000, in the PGE case (CPUC Decision 00-02-046), the Commission allocated a 50:50 sharing of all the management incentive compensation programs between ratepayers and shareholders.

California 2011: (PUC, Matthew Tisdale (CPUC), Pamela Thompson, Mark Pocta, Division of Ratepayer Advocacy, 415-703-5581) No response from California in 2011.

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1 In Docket No. 15-015-U, Order No.18, pp. 18-20, the Commission reversed a settlement treatment which disallowed only 25% of financially-based Short-term incentives, imposing instead a 50% disallowance.

California 2015: (PUC, Richard Rauschmeier, Financial Examiner, DRA - Division of Water and Audits, 415-703-2732) The Commission considers incentive compensation on a case by case basis. Plans are evaluated in the context of an overall reasonableness standard. The Commission has also established precedence for evaluating plans based on who benefits from the plans' goals, ratepayer or shareholders. This approach quite often results in different outcomes for short-term and long-term plans. In determining overall reasonableness, the Commission also considers many other criteria such as comparisons with similarly sized utilities, benchmarking to related industry, internal historical trends and overall compensation. In a recent case, A.10-07-007, staff recommended that, "customer funding should be limited to the portion of the incentive plan payments that are aligned with operational objective that provide customer benefits. This means that 70% of AIP be funded by shareholders, and 30% be funded by ratepayers." In the settlement, the Commission disallowed 50% of the plan's expense. One change that may impact consideration of incentives going forward is the Commission's renewed focus on safety since the San Bruno pipeline explosion. The Commission is establishing metrics for observing historical trends and industry comparisons, and is emphasizing neutral third-party benchmarking.

**California 2018:** (CPUC, Richard Rauschmeier, Financial Examiner, Public Advocate's Office, 415-703-2732) The CPUC examines utility company requests to include incentive compensation in rates on a case by case basis, but the criteria are well established. Generally, incentive compensation expense can be charged to ratepayers only to the extent it is aligned with ratepayer interests. Typically, this treatment results in disallowance of the portion of short-term incentives tied to financial performance [2]. The Commission's consistent practice is to reject recovery of long-term incentives, "because, LTI does not align executives' interests with ratepayer interests."[3] Since the 2010 San Bruno pipeline explosion (and other events including the Aliso Canyon Leak, and the Witch, Guejito and Rice Wildfires which were found to be caused by utilities), legislative and regulatory interest in utility safety has intensified[4]. Consequently, the treatment of incentives is increasingly framed by asking whether the incentives are safety-focused or earnings-focused.

Colorado: (PUC, Rob Trokey, 303-894-2121) Colorado has no regulatory or statutory rules governing incentive compensation and considers it on a case by case basis. In the 2006 PSC Colorado (electric utility) Rate Case 06-S-234-EG, the Office of Consumer Council argued for removing the costs of the portion of the plan not benefiting ratepayers. That case settled without the Commission ruling. In the current gas utility rate case staff is removing incentive compensation from rate base.

Colorado 2009: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882, P.B. Scheckter, Office of Consumer Counsel (OCC), 303-894-2124) Colorado has no rules or statues and, due to black-box settlements, no recent orders on point. Historically, the policy of the OCC has been to disallow plans tied to goals such as price per share, and allow in rates those plans tied to quality of service and goals that benefit ratepayers. The PUC has tended not to oppose the company's historic test year payouts. However, in the current Public Service Company of Colorado (Xcel Energy) rate case, Staff has argued to exclude all types of incentive compensation from rates. This treatment holds that incentive compensation, in general,

2 Examples of this treatment: Decision 15-11-021, Decision 12-11-051 and Decision14-08-032.
3 Decision 15-11-021 at 262
4 CPUC's view of incentives in terms of promoting a positive or negative safety culture is discussed at length in Decision 16-06-054 (San Diego Gas & Electric). Also see R.15-09-010, D.11-06-017 and Public Utilities Code Section 706.

benefits only the shareholder, that it is discretionary and sometimes is not be paid out, and that all of it should be paid for by the shareholders. The goals related to ratepayer benefit should be considered part of the job and compensated for by regular wage and salary. In this treatment, if total compensation is then non-competitive the regular, non-optional component of compensation should be raised.

Colorado 2011: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) Colorado staff has made the decision not to seek to eliminate all incentive compensation (rolling compensation for goals benefitting ratepayers into regular salaries). All executive incentives are still excluded from rates and no longer sought in company filings. Regular employee programs are judged on their benefit to ratepayers verses stockholders. Plans with metrics for goals benefiting ratepayers but dependent on an earnings per share trigger are considered to benefit shareholders and opposed by staff. Staff's approach is set forth most recently, in 10AL-963G by staff witness Kahl. The settlement in that case removed the dollar amount opposed by Kahl without specifically stating the rationale.

Colorado 2015: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) Colorado still excludes long-term executive incentive compensation from rates. However, with respect to annual incentive pay (AIP), Colorado's treatment has changed significantly. In the most recent rate case for Public Service Company of Colorado, staff recommended the Commission, "limit reimbursement of incentive pay to no more than 15 percent of employee base salary." In this Proceeding No. 14AL-0660E / Order C15-0292, the Settling Parties agreed to reduced the revenue requirement by a dollar amount without agreeing to any specific adjustments. However, on the issue of AIP, the Settlement Agreement included the statement, "the Settling Parties agree AIP incentive payment recovery in the 2017 Rate Case will be capped at 15% of an employee’s salary." This treatment does not evaluate incentive compensation plans based on some criteria such as their prudence, or which stakeholder group benefits from the goals of a plan. With respect to choosing a straight percentage of salary, Staff's witness, Fiona Sigalla, noted in her testimony of November 7, 2014: "Annual incentive plan payments to employees exceed 10 percent of salary for most workers and tops 100 percent of salary for some executives." "In 2014, the top 20 highest paid Xcel Energy executives received AIP payments that averaged over 100 percent of salary. Limiting reimbursement of incentive pay to 15 percent of base pay would mostly impact these higher paid employees." "Fifty-six percent of the impact for 2013 affects reimbursement of incentive pay for Company executives." This treatment is expected to continue at least through the term of the 2017 PSCo rate case.

**Colorado 2018:** (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) There have been no changes to the treatment of incentive compensation in Colorado since the last update to the survey. Long-term incentives are not allowed recovery in rates. Recovery of short-term plans is limited to 15% of base salary without evaluating plan goals. This treatment was followed in the PSCo Gas rate case in 2018, Proceeding No. 17AL-0363G. No change to this treatment is anticipated.

Hawaii 2011: (PUC, Steven J. Iha, Chief Auditor, 808-586-2020) Hawaii does not allow incentive compensation to be included in rates. This policy was set forth in Docket No. 6531, in the October 17, 1991 Order No. 11317. Prior Dockets in which the Commission disallowed incentive compensation include No. 3216, No. 4215, No. 4588 and No. 5114. In 6531 the Commission agreed that bonus awards tied to company income and earnings benefit stockholders, not ratepayers. The Commission further states, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." In the 1991 case, the Commission also excluded the negative deferred income taxes associated with incentive plans which were disallowed from the deferred income taxes that are deducted from the rate base.

Hawaii 2015: (PUC, Steven J. Iha, Chief Auditor, 808-586-2020) Hawaii's general policy toward incentive compensation has not changed. Incentive compensation of all types is excluded from rates. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission further stated, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." Utilities in Hawaii no longer petition to have incentive compensation expense included in rates.

**Hawaii 2018:** (PUC, Jan K. Mulvey, Chief Auditor, 808-586-2020) Hawaii's longstanding policy to exclude all incentive compensation expense from rates remains firmly in place. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission stated at page 59, "We recognize that incentives encourage cost reductions in some instances. However, we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." This treatment is not challenged by the utilities.

Idaho: (PUC, Terri Carlock, Accounting Section Supervisor, 208-334-0356) As general policy, Idaho does not allow into rates the costs associated with profits and earnings performance, but does allow a portion of plans that benefit the ratepayer through improved customer service, etc. Executive's incentive compensation plans are evaluated using the same criteria and are not often allowed. See Idaho Power Company Rate Case IPC-E-05-28 Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28 Order No. 30035, p. 4/10.

Idaho 2009: (PUC, Terri Carlock, Accounting Section Supervisor, 208-334-0356) The Commission's basic policy for evaluating incentive compensation plans involves determining who benefits, the customer or the company. This treatment has been refined (in the recent Idaho Power Company general rate case) for plans which benefit the customer but require a financial trigger (e.g. must meet a certain dividend level) to be paid. For these plans the Commission reduced the percentage allowed in rates. The Commission also now does not include any executive compensation in rates. The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness, Leckie, and in the final order for the recent IPC General Rate Case IPC-E-08-10. For earlier examples of the basic policy, see Idaho Power Company Rate Case IPC-E-05-28 Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28 Order No. 30035, p. 4/10 (attached '07).

Idaho 2011: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Treatment of incentive compensation remains unchanged in Idaho. Ms. Carlock summarizes the Idaho Public Utility Commission treatment as follows, "For Idaho utility companies, the short answer is that incentives that are based on targets that provide customer benefits, i.e. customer service, reliability, O&M budgets, safety etc., are included in rates. Incentives that are based on targets that provide shareholder value are excluded." Executive plans typically fall into the second category and are excluded. More specifically:

Idaho Power has an Executive Incentive Plan that is separate from the Annual Employee Incentive Plan, and it is excluded from rates. Avista has one plan Incentive Plan that has different targets based on different criteria. Executives participate in this plan, but because executives have a different set of targets, only the targets associated with customer service and reliability are included in rates. Pacificorp Incentive Plan, each individual employee has their own set of goals and targets in order to achieve an incentive payment, and those targets are different for executives. Executive incentives have not requested for rate recovery.

Idaho 2015: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Idaho's treatment of incentives has not changed - most is disallowed. To be included in rates a plan must benefit ratepayers. Plans based on measures which benefit shareholders, such as increased earnings, are excluded. This treatment is the same for all plans including those for executives. There are no recent orders on point, but the three rate case scheduled this year are expected to reflect this treatment.

**Idaho 2018:** (PUC, Terri Carlock, Utility Division Administrator, Accounting Section Supervisor, 208-334-0356) There has been no change to the treatment of incentives in Idaho. The Commission allows in rates those incentives that benefit customers and exclude those based on financial measures that benefit shareholders. This treatment is the same for incentives at all levels, but executive plans receive closer scrutiny as it is often harder to find customer benefit in these plans. There are no recent orders on point and no changes are anticipated in the near future.

Iowa: (Utilities Board, Wes Birchman, 515-281-5979) Incentive compensation is not an issue here as they do not do many rate cases.

Iowa 2009: (Utilities Board, Wes Birchman, 515-281-5979, Dan Fritz, 515-281-5451) Mid-America has an incentive compensation plan but hasn’t filed a rate case in many years. For the state’s other utilities, it has been a long time since they have filed a rate case or had a rate increase. The standing treatment is to look at incentive compensation plans on a case by case basis and evaluate whether or not they are reasonable and prudently incurred.

Iowa 2011: (Utilities Board, Dan Fritz, 515-725-7316) Both of the investor owned utilities in Iowa are under rate freezes until 2013 and 2014. There has been no change in the treatment of utility incentive compensation.

Iowa 2015: (Utilities Board, Dan Fritz, 515-725-7316) Incentive Compensation has not been an issue in Iowa. There are no specific treatments in place and the Commission will review the merits and prudence of a proposed plan on a case by case basis. There are no recent orders on point, and no treatment changes are anticipated.

**Iowa 2018:** (Utilities Board, Dan Fritz, 515-725-7316) There have been no changes in the treatment of Incentive Compensation. There are no specific treatments in place and the issues is handled on a case by case basis. There are no recent orders on point.

Kansas: (Corporation Commission, Utilities Div., Larry Holloway, Chief of Engineering Operations, 785-271-3222) On a case by case basis staff opposes plans without ratepayer benefit or are lacking objective measures.

Kansas 2009: (Corporation Commission, Utilities Division, Bob Glass, Chief of Economic Section, 785-271-3175) The Commission views incentive compensation plans that are based solely on financial performance as benefitting only the shareholders and not something that belongs in rates. In the last 5 to 10 years the Commission has not seen incentive compensation as a major issue and tends not to challenge plans that are reasonable by industry standards as long as they are based on a multidimensional set of criteria involving both reliability and financial goals. In Kansas, the Commission also funds the Citizens Utility Rate Board (CURB), an advocacy group for the residential and commercial ratepayers. CURB argues that any portion of a plan that relates to financial measures should be disallowed.

Kansas 2011: (Corporation Commission, Utilities Division, Jeff McClanahan, Chief of Accounting and Financial Analysis, 785-271-3212) The Kansas Commission recently has changed its stance on incentive compensation. In the litigated 2010 KCP&L rate case (10-KCPE-415-RTS) the Commission stated that relying on peer group statistics "can result in a continuing upward spiral [instead] the Commission must examine the elements of incentive packages, and the behavior they incent". For executive incentive programs, the Commission disallowed 100% of payments based on purely financial measures and 50% for plans using a balance of financial and operational measures. The Commission allowed in rates the non-executive annual incentive program after Staff found that KCP&L had modified the measures used in this plan and, "eliminated all focus on profitability or earning [which might incent employee behavior] detrimental to customers."

Kansas 2015: (Corporation Commission, Utilities Division, Justin Grady, Chief of Accounting and Financial Analysis, 785-271-3164) The Kansas Corporation Commission continues to rely on the treatment it established in the litigated 2010 KCPL rate case (10KCPE-415-RTS) and followed in the 2012 case, 12-KCPE-764-RTS. For officer level incentives, plans are evaluated to determine whether the objectives of the plan are geared to improve the company's financial results or to improve operational objectives. The financially-based portion is borne by the shareholders and the portion supporting operational goals is allowed in rates. The exception to this evaluation process are any time-based restricted stock plans which vest solely on the passage of time. Such plans are seen as being neutral and therefore split 50:50 between shareholders and ratepayers. Non-officer incentive compensation plans for workers are allowed in rates. This treatment is becoming established as the Commission's general policy[5] and has guided Staff's position on these issues in both of it current rate cases for KCPL (15-KCPE-116-RTS) and Westar (15-WSEE-115-RTS). However, the consumer advocacy branch, Citizens' Utility Ratepayer Board (CURB) has consistently recommended the more aggressive position of applying the same financial/operational criteria to non-officer plans as well. In the current KCPL rate case the company has voluntarily excluded 50% of the restricted stock plans, 100% of the performance-based plans, 50% of the short-term plans which are based on an earnings-per-share qualifier. The Company has also removed the earnings-per-share portion of their Value Rewards Plan which is open to all employees. This was seen as an attempt to find the middle ground between staff's position and that of CURB. In this case CURB did not make an adjustment challenging the company's proposed recovery.

**Kansas 2018:** (Corporation Commission, Utilities Division, Kristina Luke-Fry, Accounting and Financial Analysis, 785-271-3171) The Commission only allows in rates those incentives related to safety and other operational objectives, and excludes incentives related to

5 In the 2012 KCPL rate case (12-KCPE-764-RTS) this treatment resulted in a 50:50 split of the short-term plan. For the long-term incentives, the Commission excluded 50% of the time-based restricted stock portion of the plan, and 100% of the portion based on stockholder return.

financial measures such as earnings per share. This treatment is based on prior orders, especially 10KCPE-415-RTS. This treatment has the result of excluding the majority of executive incentives due to the fact that they are usually tied to company earnings. There are no recent orders on point, and no changes in treatment are anticipated.

Louisiana 2009: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720; Bill Barta, Henderson Ridge consulting, 770-205-8828) Louisiana has traditionally held that the incentive compensation plan for upper level management and officers are excluded from rates, while those of lower level of managers and employees are included in rates. The criteria originally used to arrive at this treatment considered whether the goals of each plan more directly benefitted ratepayers or shareholders. Recently, an ALJ's report in the Entergy Louisiana Formula Rate Plan 2006 (Docket # U -20925, 2006 Evaluation Period) has recommended excluding all stock option plans for all levels. The Commission has also recently chastised Entergy for excessive bonuses.

Louisiana 2011: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) The Louisiana Commission does not allow Executive Bonuses to be recovered from ratepayers. This is especially true for the larger utilities. For incentive awards to employees that are not Executives, the Commission may allow recovery. For some of the smaller utilities the Commission may allow bonuses to management if the whole compensation package is reasonable. There has not been any docketed proceeding since 2006.

Louisiana 2015: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) No response from Louisiana at this time.

**Louisiana 2018:** (PSC, Robin Pendergrass, Audit Director, (225-342-1457) The treatment of incentive compensation in Louisiana has not changed. The LPSC does not allow Executive incentive compensation plans to be recovered from ratepayers. Lower level management and employee incentive awards may be included, assuming they are reasonable. To determine reasonableness, the Commission looks at the amount of the incentive in relation to 1) the size of the company 2) the job duties of the employee and 3) the average hours worked during the test year. The Commission also looks at who benefits, ratepayers or shareholders. This is a general auditing policy utilized in all LPSC rate reviews. Recent dockets which followed this treatment, where disallowances were made using these criteria, include Dockets U-34667 and U-34669, which are the 2017 annual RSP filings for CenterPoint Arkla and CenterPoint Entex, respectively. Both dockets show disallowances for competitive and incentive pay and other executive compensation.

Minnesota: (PUC, Louis Sickmann, Financial Analyst, 651-201-2243) Minnesota looks at incentive packages on a case by case basis. Since the 1991 decision to deny incentive compensation costs in the ESP Electric Rate Case, the Commission has begun to allow inclusion of employee plans. It capped these plans (at 15% of base salary) out of a concern that larger percentages tied the employees too closely to shareholders' interests. Current caps are at 25% of base salaries. The portions of these plans that are allowed into rates are tracked and must be returned to ratepayers if they are not paid to employees (as has been the case when earnings per share targets were not met). Executive plans are largely not allowed. See General Rate Case E002/GR/05/1428, September 1, 2006.

Minnesota 2009: (PUC, Louis Sickmann, Financial Analyst, 651-201-2243) Minnesota's treatment of incentive compensation has changed recently. One influence that has allowed this change is that Minnesota's utilities have move away from asking the Commission to include in rates those plans that are tied strictly to company earnings. Currently plans which are based on earnings and don't include goals that benefit the ratepayer are limited to long-term management plans which are excluded from rates. The two new parts of Minnesota's treatment of plans that do benefit ratepayers are, first, to cap those plans at 25% of base salary and , second, to refund all portions of the plan which are not actually paid out to employees.

Minnesota 2011: (PUC, Jerry Dasinger, Financial Analyst, 651-201-2235) Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE), and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers are allowed in rates, but their costs are still capped at 25% of base salaries. This cap is being challenged by arguments to lower it to 15%. This general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively.

Minnesota 2015: (PUC, Sundra Bender, Financial Analyst, 651-201-2247) Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE) and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers are generally allowed in rates, but their costs are frequently capped at a percentage of base salaries such as 15% or 25% (the percentage can vary from case to case). Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Executive and long-term IC measures are frequently more closely aligned with shareholder interests and thus are not usually allowed in rates. An example of the Commission's treatment is set forth in General Rate Case G-008/GR-13-316, June 9, 2014 FINDINGS OF FACT, CONCLUSIONS, AND ORDER at pages 13-17 and page 58.

**Minnesota 2018:** (PUC, Sundra Bender, Financial Analyst, 651-201-2247) Minnesota continues to determine allowable incentive compensation on a case by case basis. Annual incentive plan compensation is usually allowed in rates, but the costs are frequently capped at a percentage of base salaries, for example: 15%, 20%, or 25% (the percentage can vary from case to case). Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Long-term IC measures are not usually allowed in rates. A recent case example is the Minnesota Power General Rate Case E-015/GR-16-664, March 12, 2018 Findings of Fact, Conclusions, and Order at pages 31-34 and 110.

Missouri: (PSC, Utility Services Div., Bob Schallenberg, 573-751-7162) On a case by case basis, Missouri includes plans that benefit consumers and otherwise disallows incentive compensation plans. The same criteria are used for executive plan – few are allowed. See recent Kansas City Power and Light and Empire Electric District orders on the Commission's website.

Missouri 2009: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) In Missouri, value to the customer is the general policy that informs their treatment of incentive compensation plans. A plan's goals must be beneficial to the customer or the plan is not allowed in rates. Plans based on rate of return, for example, are not allowed. This treatment also applies to executive plans which generally have less chance of being allowed in rates. See Ameren ER 2009-0318.

Missouri 2011: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) Missouri's treatment remains consistent in disallowing incentives tied to goals benefitting primarily the stockholders (e.g. tied to earnings per share) while allowing plans with customer-specific goals (e.g. safety). However, even these plans must be reasonable to be allowed. For example, in the last Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The Commission also removed incentive payments tied to lobbying and charitable activity. In the most recent case processed, the Ameren UE rate case, the company didn't seek even short-term incentive compensation tied to earnings demonstrating that staff's practice is becoming accepted by the companies. In that case, the Commission did allow some payments related to service, but only the amounts actually paid, not those accrued. All incentive compensation adjustment were made not only to expense charges, but to construction charges as well.

Missouri 2015: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) Incentives are addressed on a case by case basis. Plans are analyzed to determine who benefits. Plans that can show a direct benefit to customers (and that are found to be prudent) are allowed in rates. Plans that benefit shareholders are excluded. This treatment does not typically result in a different outcome (being allowed or disallowed in rates) for short-term verses long-term plans. Executive plans are less often allowed in rates due to ties to rate of return. There are no recent orders which demonstrate this treatment.

**Missouri 2018:** (PSC, Commission Staff Div., Mark Oligschlaeger, Manager, Auditing Department, 573-751-7443) Missouri's treatment for incentives, generally, is to allow rate recovery for those plans with goals that, if achieved, would lead to improved or more economical service to customers and with the goals known to employees in advance so as to be a real motivational tool. Incentives tied to financial goals such as earnings per share, net income or stock price growth are not allowed. These criteria are used to evaluate all incentive plans, short or long-term, as well as those for executives. This treatment is not proscribed by statute or rule, but has been the longstanding policy of the Commission, and was followed in the recent Spire Missouri rate cases, Case Nos. GR-2017-0215 and GR-2017-0216. There have been no recent changes to this treatment, and none are anticipated in the near future.

Montana: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no rule or policy concerning incentive compensation and no recent cases on point. They deal with the issue on a case by case basis.

Montana 2009: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no rules or recent cases dealing with incentive compensation.

Montana 2011: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no changes in its treatment of incentive compensation. It has no specific treatment directive and considers the issue on a case by case basis. In a recent NorthWestern Energy rate case, as part of a stipulation agreement, the company took a portion of its incentive compensation out of rates, but reserved the right to propose that it be included in a later filing.

Montana 2015: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Due to the low volume of litigated cases in the past 10 to 15 years in Montana, incentive compensation has not been an important issue before the Commission. This Commission is focused more on significant investment in infrastructure, such as the ongoing distribution project by NorthWestern. Incentive compensation is considered the responsibility of the utility's Board of Directors and is generally not challenged. However, the Commission tends to become more concerned by incentive plans that are tilted toward financial performance instead of operational goals. Short and long-term plans are handled similarly, and the Commission prefers plans that are broadly available to employees.

**Montana 2018:** (PSC, Gary Duncan, Revenue Requirements and Audits, 406-444-6189) Incentive compensation has not been a contested issue in the three rate cases in Montana since the 2015 survey. All utility compensation, including incentives, is recovered through rates in Montana.

Nebraska: (Public Service Commission, Laura Demman, Director and Legal Counsel, Natural Gas Department, NPSC, 402-471-3101) Nebraska is unique in that all of its electric demand is supplied by consumer-owned power districts, cooperatives, and municipalities. The Natural Gas Department of the NPSC regulates the rates and service quality of investor-owned natural gas public utilities pursuant to the state's Natural Gas Regulation Act passed in 2003. Nebraska does not have rules regarding incentive compensation and considers the issue on a case by case basis. In a 2007 rate case, NG-0041, with Aquila (later acquired by Black Hills), the Commission allowed in rates only the actual amounts paid, an adjustment to provide for a known and measurable expense. This order further adjusted the company's application by half, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit." In a subsequent Black Hills case, NG-0061, the Commission again ordered a "known and measurable" adjustment. In NG-0060 the Commission disallowed the entire amount requested by SourceGas for cash incentive bonuses citing insufficient information on the record to adequately describe the bonuses.

Nebraska 2015: (Public Service Commission, Angela Melton, Director and Legal Counsel, Natural Gas Department, NPSC, 402-471-3101) There has been no change in the treatment of incentive compensation as a ratemaking issue in Nebraska.

**Nebraska 2018:** (Public Service Commission, Nichole Mulcahy, Director and Legal Counsel, Natural Gas Department, 402-471-0234) There have been no changes in Nebraska’s handling of incentives. The Commission still practices the policy that cost should follow benefit and allows in rates the actual amount paid on incentive plans that benefit ratepayers. This treatment is the same for all incentive plans. There are no recent orders on point and no changes are anticipated.[6]

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6 In a 2007 rate case, NG-0041, the Commission disallowed 50%, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit."

Nevada: 100% of long-term incentives are disallowed. Short-term incentives are divided between financial and operational goals with 100% of financially based plans disallowed. In Nevada Power's 2008 rate case, the Commission excluded 100% of the long-term plan for executives and key employees of the company, based on the fact that these costs mainly benefit shareholders. In Nevada Power's 2011 rate case, Docket No. 11-06006, the Company voluntarily excluded the costs of its long-term plan.

Nevada 2015: No change in Nevada's treatment.

**Nevada 2018:**

New Mexico: (Public Regulation Commission, Charles Gunter, Accounting Bureau, 505-827-6940) The technical staff takes the general position that the portion of an incentive program that is based on increasing share value should be paid for by shareholders. Any that benefits ratepayers and makes up part of a reasonable base pay should be part of rates. Plans are evaluated on a case by case basis. Charles Gunter writes, "Staff took the position that 20 percent of Public Service Company of New Mexico's Results Based Pay costs were properly allocable to customers, because 20 percent of the maximum possible RBP award was tied to achieving goals pertaining to customer satisfaction, cost control, safety, reliability and operations efficiency. By comparison, 80 percent of the maximum possible award was tied to achieving corporate financial goals and EPS targets. See pages 11-13 of Andria Delling's (505-827-6962) testimony in 06-00210-UT."

New Mexico 2009: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6975) The Commission does not favor incentive compensation plans that are tied to financial goals and tends to allow in rates those based on operational goals. This standard is applied to plans at all levels of utility employees and tends to knock out a greater proportion of executive plans. See Docket 07-00077-UT

New Mexico 2011: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) There has been no change in NMPRC's treatment of incentive compensation except that due to the current economic conditions, Staff is even more opposed to incentive compensation and wage increases.

New Mexico 2015: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) Incentive programs tied to measures that benefit ratepayers (such as operation and safety) are allowed in rates. Programs tied to the financial performance of the utility (e.g. stock price or ROE) are not allowed in rates. Executive incentive plans receive more scrutiny as they are more likely to have financial measures. They can also be challenged if the overall percentage is out of line. One major utility in New Mexico no longer includes the compensation of its top 5 executives in rate applications. The treatment of incentive compensation as a ratemaking issue has become generally established by practice and plans are considered on a case by case basis. There are no recent orders setting out this treatment, and no changes are anticipated.

**New Mexico 2018:** (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) ) There has been no major change in the treatment of incentive compensation since the last update. The Commission considers this issue on a case by case basis and generally allows recovery through rates of those incentives that are reasonable in amount and tied to metrics that have benefit for customers, such as operational excellence and safety. Incentives that are financially based, for example those tied to stock price performance or earnings, are not allowed in rates. This treatment was followed in the Southwest Public Service Company's 2017 rate case, 17-00255-UT. The Commission described this treatment as its longstanding practice in the order in Public Service Company of New Mexico's rate case, 15-00261-UT. Some utilities in New Mexico no longer seek recovery of management incentives in rates.

North Dakota: (PSC, Mike Diller, Director of Accounting, 701-328-4079) In North Dakota, the general policy is the portion that relates to earnings of the shareholders is disallowed and the rest is included.

North Dakota 2009: (PSC, Mike Diller, Director of Accounting, 701-328-4079) Historically, North Dakota has followed the general policy that the portion of incentive compensation that relates to shareholder earnings is disallowed and the rest is included. The issue has recently been reframed. In the last rate case (Xcel/Northern States Power Company) the Commission followed the "Minnesota Solution": they capped incentive compensation for employees at 15% of base pay (company had asked for 25%). Any incentive compensation over the 15% level was not included in rates. Executive incentive compensation was not allowed in rates, and was not sought by the company to be in rates in this case nor in the last Xcel case (see p. 2, of McDaniel, Direct – attached; and p. 46, C of A.E. Heuer).

North Dakota 2011: (PSC, Mike Diller, Director of Accounting, 701-328-4079) The Commission has not accepted the financial verses performance, or shareholder verses ratepayer perspective on incentive compensation as recently argued by witness George Mathai. The Commission chose to look at the overall compensation and judge whether or not it was reasonable compared to the market. Other than Xcel, the utilities in North Dakota (Otter Tail and MDU) are highly diversified now (with mostly unregulated operations, e.g. MDU 90%). This allows utility executives to draw on the unregulated components for their compensation.

North Dakota 2015: (PSC, Mike Diller, Director of Accounting, 701-328-4079) Incentive compensation is dealt with on a case by case basis and there is no standard policy for the issue. The Commission has in the past limited incentives to 15% of salary. The general approach is to determine if incentive compensation is reasonable and fair based on market analysis. There have been no recent orders on point, and no changes in treatment are anticipated.

**North Dakota 2018:** (PSC, Patrick Fahn, Director of Public Utilities Division, 701-328-4079) Incentives are treated on a case by case basis, but the Commission's general policy is to allow in rates incentive compensation that is tied to customer benefit and to disallow incentives tied to company financials and corporate benefit. This treatment is the same for all types of incentive plans. Executive incentives are always requested by the utilities but are historically not allowed in rates unless shown that the incentive compensation is tied to customer benefits. The current 2017 Otter Tail rate case, PU-17-398, is expected to follow this treatment. No changes to this treatment are anticipated in the near future.

Oklahoma : The Commission excludes incentive payments tied to financial performance. From a practical perspective this means that all executive stock plans are excluded and some portion of the annual cash plan for all employees. Since the Commission has not been able to determine in recent years the precise portion of the annual plans tied to financial measures, the Commission has excluded 50% of the expense. All of the executive stock plan costs are routinely excluded. (See Commission orders in AEP-PSO Cause No. PUD 06-285; OG&E Cause No. PUD 05-151; and ONG Cause No. PUD 04-610).

Oklahoma 2009: The Commission's policy toward incentive compensation is unchanged in 2009. In AEP-PSO's recently decided rate case (final order issued 1-14-09), the Commission exclude all of the long-term incentive compensation plans and 50% of the annual plans. (See Final Order No. 464437 in AEP-PSO Cause No. 08-144).

Oklahoma 2011: The Commission's policy toward incentive compensation is unchanged in 2011.

Oklahoma 2015: No change in Oklahoma's treatment.

**Oklahoma 2018:** No change in Oklahoma's treatment.

Oregon: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) Oregon PUC's general policy is that all officer bonuses are 100% deleted from rates. For employee incentives plans, the part that is based on customer service is allowed and the part that is based on increased return is disallowed, resulting in 50-50 to 70-30 splits between shareholders and ratepayers. Utilities have begun to adopt this structure in their IC plans.

Oregon 2009: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) No substantial change in treatment. The Commission's general policy is to evaluate plans based on whether they benefit the customers or the company. Customer-based plans (involving reliability, response speed, etc) are called "merit" plans. Company-based plans (which track increases to the bottom line, ROE, etc) are called "performance" plans. 50% of the cost of merit plans is disallowed from rates and 75% of performance plans are disallowed from rates. 100% of officer bonuses are disallowed. A recent order reflecting this policy is found in Docket UE 197, Order No. 09-020 (attached).

Oregon 2011: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) No change in treatment. Still categorize "merit" or "performance" plans and disallow from rates 50% and 75% respectively. 100% of officer bonuses are disallowed.

Oregon 2015: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) The Commission's general policy is based on the idea that customers should not have to pay for incentive compensation based on financial goals such as rate of return. This treatment typically results in 50% to 75% of short-term incentives being allowed in rates. However, in the case of a plan with 3 of its 4 goals based on financial measures, 75% of the cost of that plan would be excluded from rates. The only long-term plans are for officers, and 100% of officer incentives are excluded from rates. This treatment is not expected to change.

**Oregon 2018:** (PUC, John Crider, Administrator - Energy Rates, Finance and Audits Division, 503-373-1536) The treatment of incentives in Oregon has not changed. Short-term, non-officer incentive plans are seen as having benefit to ratepayers; 50% of merit-based plans are disallowed from rates and 75% of plans related to company performance are disallowed[7]. Long-term officer and executive plans are seen as benefitting shareholders and are 100% disallowed[8]. This is a long-standing policy based on previous orders.

South Dakota: (PUC, Dave Jacobson, Analyst, 605-773-3201) The criteria used here is incentives that are triggered by shareholder returns are disallowed.

South Dakota 2009: (PUC, Dave Jacobson, Analyst, 605-773-3201) The Commission's general policy is to disallow the portion of incentive plans that are based strictly on returns. Current treatment also includes disallowing both executive and non-executive management incentive compensation. Also, there are no incentive compensation plans for union employees. Rate cases settle here so there are no orders on point.

South Dakota 2011: (PUC, Dave Jacobson, Analyst, 605-773-3201) South Dakota PUC is opposed to including in rates incentive compensation plans based on the company's financial performance. In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010 in the Black Hills Power rate case Docket No. EL09-018 the Staff Memorandum states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation." Jacobson noted that several utilities have whole incentive programs that hinge on whether or not the company earns a certain return. These financial prerequisites cause the whole plans to be excluded from rates. The same treatment is used for management and employee plans.

South Dakota 2015: (PUC, Eric Paulson, Utility Analyst, 605-773-6347) South Dakota considers incentive compensation on a case by case basis. Their general policy is to evaluate each plan and disallow the portion based on financial performance indicators. This treatment is set forth in the recent case EL14-026 in which the order specifically excluded the amount "tied to the Company's financial results." This policy is not anticipated to change.

**South Dakota 2018:** (PUC, Eric Paulson, Utility Analyst, 605-773-6347) There has been no change in South Dakota's treatment of incentives since 2015. Incentives with stockholder-benefiting financial goals are excluded from rates. This treatment is the same for incentive plans at all levels. Recent orders (issued 6/15/16) which follow this treatment are found in dockets EL 15-024 and NG 15-005. This treatment is not expected to change.

Texas: The Public Utility Commission regulates the electric utilities in Texas. The PUC's general rule is that incentive payments designed to increase the financial position of the utility are excluded. For example, in PUC Docket No. 28840, the Commission disallowed sixty-six percent (66%) of AEP-Texas Central's test year incentive payments in the amount of $4.2

7 See Orders: 76-601 p.13, 77-125 p. 10, 87-406 pp. 42-43

8 See Orders: 99-033 p. 62 and 97-171 pp.74-76

million. This was the portion of the utility's incentive payments that was based on financial performance measures. (See Application of AEP Texas Central Company for Authority to Change Rates, Docket No. 28840; SOAH Docket No. 473-04-1033, Final Order, August 15, 2005; ALJ's Proposal for Decision at page 113 in PUC Docket No. 28840, SOAH Docket No. 473-04-1033, issued July 1, 2004. The PFD with respect to the treatment of incentive compensation was adopted by the Commission in its Final Order.)

Gas utilities are regulated by the Railroad Commission. The treatment of the RRC is consistent; financial incentives are out of rates and customer-related incentives are allowed in. Examples of this treatment can be found in Atmos 9670 Order and Order on Rehearing, Texas Gas Service Company 9988 Final Order, Centerpoint 9902 Final Order and Centerpoint 10106 Final Order. In Docket 9670 both the executive and employee plans for Atmos Mid-Tex were found not to be just and reasonable because they, "advanced the interest of shareholders, and [are] driven by Company earnings." None of the costs of these programs were allowed in rates. In Docket 9988 the RRC found 100% of long-term and 90% of short-term incentives expense was "unreasonable" because it was related to the financial performance of ONEOK Inc. 10% of the short-term plan was allowed in rates because it was based on safety metrics.

Texas 2015: (PUC, Larry Reed, Senior Fuel Analyst, 512-936-7357) No response from Texas PUC at this time. A recent example of the Texas commission's well established policy of excluding financially based incentives is set forth in 2011 rate case of Entergy Texas Inc. (PUC Docket No. 39896). In PUC Docket No. 40295, Entergy's application for rate case expense in the 39896 case, the Commission also disallowed the amount of rate-case expenses related to financially-based incentive compensation. The 40295 Order reads at page 2:

> The Commission affirms the proposal for decision regarding the need to reduce Entergy's recoverable expenses due to an unreasonable position pursued by Entergy in the rate case and also affirms the use of the "issue-specific reduction approach" to determine how to calculate an appropriate reduction in rate-case expenses when the utility takes positions that are in conflict with Commission precedent.
>
> Specifically, the Commission agrees with the ALJ that reductions should be made to Entergy's recoverable rate-case expenses for Entergy attempting to recover financially-based incentive compensation in base rates. The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services.[9] The Commission concludes that it should follow its well-established policy here.
>
> However, the ALJ did not include all of the impacts attendant to the disallowance for incentive compensation.[10] To

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[9] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Finding of Fact No. 93, Order on Rehearing at 22 (Nov. 30, 2009); and *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011).

[10] Docket No. 39896, Order on Rehearing at 5-6, 7-8 (Nov. 2, 2012).

calculate the amount of the reduction in rate-case expenses related to financially-based incentive compensation, the Commission starts with Entergy's initial rate-case expense request, reduced by $208,494 in disallowances made by the ALJ and affirmed by the Commission. The Commission further reduces this amount by an additional $522,244.66, which is the amount of rate-case expenses related to financially-based incentive compensation using the issue-specific reduction approach.

Texas 2015: (Railroad Commission, Mark Evarts, Director, Market Oversight and Safety Services Division, 512-427-9057) No response from Texas RRC at this time.

**Texas 2018:** (PUC, Anna Givens, Director, Financial Review, 512-936-7462) The longstanding policy of the Commission is to exclude from rates all financially-based incentives. Incentives based on operational goals may be included in rates. Long-term incentives are typically financially based and are excluded. Executive incentives receive the same treatment. This treatment is not proscribed by statute or rule, but has been the consistent policy of the Commission since 2005 when it issued the Final Order in Docket No. 28840. Recent orders in litigated cases that set forth this treatment include SWEPCO rate cases Docket Nos. 40443 and 46449, and the SPS rate case Docket No. 43695. One recent refinement to the treatment of this issue in Texas is that for plans that are otherwise based on acceptable operational metrics but are paid only if a financial goal is met, only 50% of the portion that is subject to the financially-based proviso is allowed in rates. This split occurs before consideration of the individual components of the compensation plan goals and 100% of incentive plan goals tied directly to financial goals are further excluded. In the SWEPCO proceeding, Docket No. 46449, the Company's EPS funding goal was weighted 75%, so the disallowance was 50% of the 75% weighting and resulted in an adjustment that was less than 50% of the total plan that was otherwise based upon acceptable operational metrics. This refinement reflects that a plan has a financially-based funding trigger and requires employees to meet metrics that include financial goals, in addition to performance-related goals. There are no imminent changes in the PUC's treatment, however there are some efforts to have it codified as a Commission Rule.

**Texas 2018:** (Railroad Commission, Mark Evarts, Director, Market Oversight and Safety Services Division, 512-427-9057) No response from the RRC at this time.

Utah: (PSC, Jim Logan, Commission Utility Economist (PSC), 801-530-6716) The general policy in Utah is the portion of the plan based on rate payer benefit, such as service quality, is allowed and the portion that relates to earning and rate of return are disallowed. See US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01 Order signed 3/4/99, pp. 10-12.

Utah 2009: (PSC, Jim Logan PhD, Commission Utility Economist (PSC), 801-530-6707) The Commission's general policy (backed by orders) is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. Executive incentive compensation is excluded from rates. The recent final order in 07-035-93 follows this general policy. See also US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01 Order signed 3/4/99, pp. 10-12.

Utah 2011: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) There have been no changes in Utah's treatment of incentive compensation. The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals.

Utah 2015: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. This policy was followed in the PacifiCorp General Rate Case Docket No. 07-035-93, pp. 61-62; the US West Communications Rate Case Docket 95-049-05; and Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12. There are no recent orders on point and no changes in policy are anticipated.

**Utah 2018:** (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) There have been no changes to the treatment of incentives in Utah. The Commission's general policy is still to allow in rates incentives tied to ratepayer benefit and disallow those tied to financial goals of the utility. No rate cases have been litigated since the last update in 2015, so there are no recent orders on point. No changes in policy are anticipated.

Washington: (WUTC, Roland Martin, staff, 360-664-1304) Treated on a case by case basis. Typically allow the component tied to efficiency increases and disallow the part that results from increasing the bottom line. See Docket 061546, Pacific Power and Light, Order

Washington 2009: (WUTC, Roland Martin, staff, 360-664-1304) No change in treatment. Evaluated on a case by case basis, this treatment allows the parts of plans tied to measures such as reliability and customer satisfaction and disallows the parts tied to financial measures and the bottom line.

Washington 2011: (WUTC, Roland Martin, Regulatory Analyst, 360-664-1304) No change in treatment. Still addressed on case by case basis, allowing in rates those incentives that are tied to operational efficiency or other measures which benefit ratepayers, and disallowing incentives based on return on earnings or other measures that benefit the shareholders. Recommended website: www.utc.wa.gov.

Washington 2015: (WUTC, Roland Martin, Regulatory Analyst, 360-664-1304) No change in treatment. Still addressed on case by case basis, allowing in rates those incentives that are tied to operational efficiency or other measures which benefit ratepayers, and disallowing incentives based on return on earnings or other measures that benefit the shareholders.

**Washington 2018:** (WUTC, Amy Andrews, Regulatory Analyst, 360-664-1304) Washington's treatment of incentive compensation is largely based on previous cases, and is not a highly contested issue. Short-term incentives are generally allowed in rates and Long-term incentives are excluded.

Wyoming: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Wyoming considers incentive compensation on a case by case basis. The general approach is to determine if the program is reasonable.

Wyoming 2009: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Executive incentive compensation plans are all excluded from rates. Employee incentive compensation plan are evaluated on a case be case basis. Criteria for evaluation include that optional portions of the plans are based on performance goals not financial measures, and the total compensation is compared to a market standard. Currently most employee plans meet these criteria and are allowed in rates.

Wyoming 2011: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Policy here remains the same, distinguishing between employee programs that benefit the ratepayer or the stockholders and requiring the benefitting party to pay. Executive plans are excluded.

Wyoming 2015: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Incentive compensation has not been an issue in some time here. There are no governing regulations, statutes or general policies and the issue would be decided on a case by case basis after considering the history and goals of a program in the context of a rate case. There are no recent orders on point, and no changes in treatment are anticipated.

**Wyoming 2018:** (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) There has been no change in the way that incentives are treated in Wyoming. Incentives are generally evaluated on a case by case basis to determine if they are just and reasonable, giving attention to plan goals and historical context. There are no governing regulations, statutes or general policies in place, and there are no recent orders on point. No changes in treatment are anticipated.

**AFFIRMATION**

I affirm, under the penalties for perjury, that the foregoing representations are true.

M. Garrett

Mark E. Garrett
President of Garrett Group Consulting, Inc.
Indiana Office of Utility Consumer Counselor
Cause No. 45235
Indiana Michigan Power Company

8/19/2019

Date

## CERTIFICATE OF SERVICE

***Indiana Office of Utility Consumer Counselor Public's Exhibit No. 2 Testimony of OUCC Witness Mark E. Garrett*** has been served upon the following parties of record in the captioned proceeding by electronic service on August 20, 2019.

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