**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, FOR APPROVAL OF: REVISED DEPRECIATION RATES; ACCOUNTING RELIEF; INCLUSION IN BASIC RATES AND CHARGES OF THE COSTS OF QUALIFIED POLLUTION CONTROL PROPERTY; MODIFICATIONS TO RATE ADJUSTMENT MECHANISMS; AND MAJOR STORM RESERVE; AND FOR APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS.** | ) | **CAUSE NO. 44075** |

**PROPOSED ORDER SUBMITTED BY THE INDIANAOFFICE OF UTILITY CONSUMER COUNSELR (OUCC)**

The Indiana Office of Utility Consumer Counselor submits the attached proposed order.

Respectfully submitted,

Daniel M. Le Vay, Atty. 22184-49
Deputy Consumer Counselor

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**ORDER OF THE COMMISSION**

**Presiding Officers:**
**Kari A. E. Bennett, Commissioner**
**Jeffery A. Earl, Administrative Law Judge**

On September 23, 2011, Indiana Michigan Power Company ("Petitioner," "Company" or "I&M") filed a Petition with the Indiana Utility Regulatory Commission ("IURC" or "Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below. On September 23, 2011, Petitioner also filed its Case-in-Chief, workpapers and information required by the minimum standard filing requirements ("MSFRs") set forth at 170 IAC 1-5-1 *et seq.* On September 23, 2011, Petitioner also filed a motion to protect from public disclosure certain confidential information, which motion was subsequently granted by the presiding officers and this ruling is now affirmed.

Petitions to Intervene were filed by Citizens Action Coalition of Indiana, Inc. ("CAC"), City of Fort Wayne ("Fort Wayne"), City of South Bend ("South Bend"), Steel Dynamics, Inc. ("SDI"), I&M Industrial Group, whose members are the following industrial customers: Air Products & Chemicals, Inc., The Linde Group, Marathon Petroleum Company LLC, Praxair, Inc., General Motors Corporation, I/N Tek, Saint-Gobain Containers and New Energy Corp. ("Industrial Group"), the Kroger Company ("Kroger"), Inovateus Solar LLC ("Inovateus"), Ecos Energy ("Ecos") and AEP Indiana Michigan Transmission Company, Inc. ("IM Transco"). All but one of these petitions were granted without objection. Ecos' petition was granted over I&M's

objection. The intervening entities were made Parties to this Cause. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated as a Party.

On November 2, 2011, the Commission issued a Prehearing Conference Order in this Cause which, among other things, established a procedural schedule. On February 2, 2012, Petitioner prefiled its supplemental direct testimony, exhibits and workpapers updating its rate base as of December 31, 2011. Pursuant to the Prehearing Conference Order, and notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public evidentiary hearing in this Cause was held on February 20, 2012 and continued through February 28, 2012, at which time Petitioner presented its Case-in-Chief and its witnesses were cross-examined.

During three public field hearings conducted pursuant to legal notice, written and verbal comments from Petitioner's customers were made a part of the evidentiary record. The first field hearing was held on April 23, 2012 in the City of Fort Wayne, the largest municipality in Petitioner's Indiana service territory. The other two public field hearings were held in the Cities of South Bend and Muncie on April 24 and 25, 2012, respectively. The OUCC also received written public comments from numerous interested I&M customers throughout this proceeding, the first of which were filed with the Commission on March 31, 2012.

On April 27, 2012, the OUCC and certain Intervenors filed their respective cases-in-chief. On May 25, 2012, the OUCC and Intervenors filed their respective cross-answering testimony and Petitioner filed its rebuttal testimony, exhibits, Major Project Update and workpapers.

On June 5, 2012, I&M filed its Petitioner's Submission of Omitted Rebuttal Exhibit and Correction to Rebuttal Testimony and on June 13, 2012, I&M filed its Petitioner's Submission of Corrections to Rebuttal Testimony.

On June 13, 2012, the OUCC filed its Motion to Strike Portions of Petitioner's Witness David Moody's Rebuttal Testimony ("OUCC's Motion"). On June 13, 2012, I&M filed its Petitioner's Response to Motion to Strike and the OUCC filed its Reply to Petitioner's Response to Motion to Strike on June 22, 2012. At the evidentiary hearing on June 25, 2012, the OUCC's Motion was denied. [Tr. at DD-5-DD-6].

Pursuant to the notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public evidentiary hearing in this Cause was held on June 18, 2012 and continued through June 28, 2012, at which time the OUCC, Intervenors and Petitioner presented their evidence and offered their witnesses for cross-examination. Following the hearing post hearing proposed orders and briefs were filed in accordance with the schedule set forth in the Prehearing Conference Order.

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

**1. <u>Notice and Jurisdiction.</u>** Due, legal and timely notice of the filing of the Petition in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Due, legal and timely notices of the Prehearing Conference and the public hearings in this Cause were given and published as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission. This Commission has jurisdiction over Petitioner and the subject matter of this proceeding in the manner and to the extent provided by the laws of the State of Indiana.

**2. <u>Petitioner's Organization and Business.</u>** I&M, a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), is a corporation organized and existing under the laws of the State of Indiana, with its principal offices at One Summit Square, Fort Wayne, Indiana. I&M is a member of the East Zone of the AEP System, which is operated on an integrated basis pursuant to the AEP Interconnection Agreement, a Federal Energy Regulatory Commission ("FERC") - approved agreement that defines the sharing of costs and benefits associated with certain AEP East Zone affiliates' respective generating plants ("AEP Interconnection Agreement"). I&M is engaged in, among other things, rendering electric service in the States of Indiana and Michigan. I&M owns, operates, manages and controls plant and equipment within the States of Indiana and Michigan that are in service and used and useful in the generation, transmission, distribution and furnishing of such service to the public. I&M has maintained and continues to maintain its properties in an adequate state of operating condition.

I&M provides electric service to approximately 586,000 retail customers within a service area covering approximately 8,260 square miles in northern and east-central Indiana and southwestern Michigan. In Indiana, I&M provides retail electric service to approximately 458,000 customers in the following counties: Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells and Whitley. In Michigan, I&M currently provides retail electric service to approximately 128,000 customers. In addition, I&M serves customers at wholesale in the States of Indiana and Michigan. I&M's electric system is an integrated and interconnected entity that is operated within Indiana and Michigan as a single utility. I&M's transmission system is under the functional control of PJM Interconnection, L.L.C., a FERC-approval regional transmission organization ("RTO"), and is used for the provision of open access nondiscriminatory transmission service pursuant to PJM's Open Access Transmission Tariff ("OATT") on file with the FERC. As a member of PJM, charges and credits are billed to AEP and allocated to I&M for functional operation of the transmission system, management of the PJM markets, and general administration of the RTO.

I&M renders electric service by means of electric production, transmission and distribution plant, as well as general property, equipment and related facilities, including office buildings, service buildings and other similar properties which are used and useful in the generation, purchase, transmission, distribution and furnishing of electric energy for the convenience of the public (collectively referred to as "Utility Property"). I&M's Utility Property is classified in accordance with the Uniform System of Accounts ("USOA") as prescribed by FERC and approved and adopted by this Commission.

**3. <u>Existing Rates.</u>** I&M's existing retail rates in Indiana were established pursuant to the Commission's orders in Cause No. 43306 based upon test year operating results for the twelve months ended September 30, 2007, adjusted for fixed, known and measurable changes. The petition initiating Cause No. 44075 was filed with the Commission on September 23, 2011. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than fifteen months has passed between I&M's last petition and I&M's most recent request for a general increase in its basic rates and charges.

4. **Relief Requested.** In its Petition in this proceeding, I&M requested authority to increase its rates and charges for electric utility service and approval of: revised depreciation rates; accounting relief; inclusion in basic rates and charges of the costs of Qualified Pollution Control Property ("QPCP"); modifications to rate adjustment mechanisms; a major storm reserve and new schedules of rates, rules and regulations. As shown by Petitioner's Exhibit SMK-R1, I&M requests the Commission approve an increase in annual revenues from basic rates of $170,131,845 million. After accounting for offsets and decreases in existing rate adjustment mechanisms, the Company's overall proposal results in a net annual increase in revenues of $140,351,382 or 9%.

5. **Test Year.** As provided in the Prehearing Conference Order, the test year to be used for determining Petitioner's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the twelve months ended March 31, 2011, adjusted for changes that are fixed, known and measurable for ratemaking purposes and that occur within twelve months following the end of the test year.

6. **Overview.** I&M's President and Chief Operating Officer, Paul Chodak III, provided a general overview of Petitioner's request and discussed why I&M petitioned for a rate increase. He stated that from the end of the test year used to establish I&M's current rates (September 30, 2007) through November 30, 2011, I&M's capital investment to expand and improve its distribution, transmission and generation facilities used to provide service to customers has increased on an Indiana jurisdictional basis by approximately $411 million. Chodak Direct, at 16 (Revised). Mr. Chodak stated the Company's earnings are currently below the authorized level. Petitioner claimed that absent timely regulatory relief, the Company's financial position will continue to deteriorate. As revised in its rebuttal case, Petitioner proposed an increase in its rates to produce an additional $170,132,000 or a 13.18% increase across the board. Petitioner's proposed rates include requests for a fair value increment, a cost of equity of 11.15%, inclusion of discretionary pension payments in rate base, reducing its $37.5 million off-system sales margin credit to zero, recovery of carbon capture and storage study costs, special regulatory accounting treatment for major storm damage expense, continuation of nuclear decommissioning expense, and recovery of costs Petitioner incurred beginning in 2010 to reduce the size of its workforce.

The OUCC and the several Intervenors in this Cause did not agree with Petitioner's proposed rates and regulatory changes. For instance, the OUCC proposed a 2.14% increase to Petitioner's rates of $27,740,964, compared to Petitioner's proposed increase of $170,132,000. In its case-in-chief, the OUCC proposed a cost of equity of 9.20%, denial of the fair value increment, disallowing the inclusion in rate base of Petitioner's discretionary pension payments, reducing its $37.5 million off-system sales margin credit to $32.9 million, no recovery of carbon capture and storage study costs, no special regulatory accounting treatment for major storm damage expense, discontinuation of nuclear decommissioning expense due to that expense already being met, and no recovery of the costs Petitioner incurred in the past to reduce its workforce. The OUCC also proposed elimination of various expenses that Petitioner proposed to include in rates. The OUCC disagreed with Petitioner's proposed depreciation rates and with some proposed tariff provisions and rate design changes. The OUCC also noted the significant capital projects for which Petitioner was seeking approval in other cases. More specifically, the OUCC noted I&M is currently obligated by its NSR Consent Decree with the Department of Energy to install SO2 and NOx controls at its Rockport Unit 1 by the end of 2017 and at Rockport Unit 2 by the end of 2019 at a cost of $1.4 billion per plant. The OUCC noted that I&M also has the opportunity to secure for its customers the continued availability of the Cook Plant during the 20 year extension by performing a systemic asset management project known as LCM, which will cost approximately $1.1 billion. In addition, I&M may need to install a cooling tower at the Cook Plant which is estimated to cost approximately $1 billion[1]. The OUCC noted that AEP/I&M may need to invest approximately $4.5 billion in plant over the next 8 years based on current forecasts. The OUCC estimated these capital projects would cause a need to increase Petitioner's rates by 37%, not including any additional associated operating expenses.

**7. New Depreciation Rates.** I&M requested a change in its current depreciation rates. Ind. Code § 8-1-2-19 authorizes the Commission to "ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility." I&M's requested rates would produce an increase in annual depreciation expense of $36,691,313 compared to current rates on a total Company basis using depreciable plant balances at December 31, 2010. The OUCC raised several depreciation issues and recommended depreciation rates that produce an increase in annual depreciation expense of $16,290,171 compared to current rates, on a total Company basis using depreciable plant balances at December 31, 2010. IG witness Mr. Selecky presented testimony that would produce a steam production depreciation annual expense that is $7.794 million less than produced by I&M's proposed steam production rates, on a total Company basis using depreciable plant balances at December 31, 2010. Mr. Selecky did not address depreciation rates other than for steam production plants.

**A. I&M Case-in-Chief.** I&M Witness David A. Davis, AEPSC Manager - Property Accounting Policy and Research, testified in support of revised depreciation accrual rates for I&M's electric plant in service. He said the depreciation rates determined by the study he conducted are intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected life of the property. He said the revised depreciation rates are primarily required due to changes in investment, expected life and net salvage of I&M's property that takes into account recently proposed U.S. Environmental Protection Agency ("USEPA") national standards. Davis Direct, at 4. Mr. Chodak said the revised depreciation rates will allow I&M's depreciation expense to more closely match the recovery of its investment with the period in which the plant provides service to customers. Chodak Direct, at 22. Mr. Chodak also said compliance with the federal mandate increases total depreciation expense by $3 million.

Mr. Davis presented a comparison of I&M's current depreciation rates and accruals and the depreciation rates and annual accruals reflected in the depreciation study. Davis Direct, at 5-

[1] See Petitioner's Witness Chodak's testimony page 25, lines 7 - 10.

6. Based on results of the study and applying I&M Indiana rates to total Company plant in service, he suggested an increase in annual depreciation expense of $36,691,313 on a total Company basis using depreciable plant balances at December 31, 2010. *Id.* at 6.

Mr. Davis said the property included in the depreciation report was considered on a group plan, under which depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group instead of individual items of property. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. Also under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. Mr. Davis said the plant groups consisted of the individual primary plant accounts for Production, Transmission, Distribution and General Plant property. The depreciation rates were calculated by the Average Remaining Life Method. *Id.* The Remaining Life method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation over the average remaining life of the plant. *Id.* at 7-8.

Mr. Davis said, for Production Plant, the generating unit retirement dates and the interim retirement history for the individual plant accounts were used to determine the average service lives and the remaining lives of the plants. He said the average service lives for the Company's Transmission, Distribution and General Plant were determined using statistical procedures similar to those used in the insurance industry in studies of human mortality. The historical retirement experience of property groups was studied and retirement characteristics of the property were described using the Iowa-type retirement dispersion curves. Net salvage for each property group was determined based on actual historical experience for Production, Transmission, Distribution and General Plant accounts. In addition, Production Plant included terminal retirement net salvage amounts for Steam Production Plant. Mr. Davis said to determine these amounts, I&M commissioned the independent engineering firm, Sargent & Lundy ("S&L"), to update their conceptual dismantling cost estimates that are included in I&M's current depreciation rates for the Tanners Creek and Rockport Plants. He said the recommended depreciation rates for Production Plant included the dismantling cost for Tanners Creek and Rockport Plants at their estimated retirement dates. *Id.* at 8.

Mr. Davis indicated S&L provided terminal net salvage amounts excluding any asbestos, ash pond or landfill type removal costs that were stated at a 2010 price level. He used a 2.5% inflation rate factor to the net salvage amounts provided by the S&L study to determine the terminal net salvage amount at each plant's retirement year. He said the terminal net salvage amount after inflation was used in the calculation of net salvage percentages in the depreciation study. *Id.* Mr. Davis said the 2.5% inflation rate was taken from a publication titled "The Livingston Survey" dated December 9, 2010. The Livingston Survey provides a long term inflation outlook projecting an inflation rate for a 10 year period. *Id.* at 9.

Mr. Davis said the cost to remove asbestos and to cover ash ponds and landfills were excluded from the S&L steam plant dismantling study because these amounts are included in the Company's accounting for asset retirement obligations ("ARO") and the depreciation and accretion on these ARO's are incorporated in cost of service outside of the depreciation study. *Id.* at 9-10.

Mr. Davis said he calculated separate depreciation rates for the Tanners Creek Selective Non-Catalytic Reduction ("SNCR") Project and Rockport's Activate Carbon Injection ("ACI") System because the depreciable life for these systems was established and approved by the Commission in Cause No. 43636. *Id.* at 10. He indicated the depreciation rates for this equipment have been updated to reflect current estimated remaining lives.

Mr. Davis said based on the depreciation study, the composite depreciation rate for Steam Production Plant increased from 1.85% to 3.05% primarily due to a 6 year shorter life estimate for Tanners Creek Units 1-3 and an increase in Rockport and Tanners Creek plant investment since the prior depreciation study. *Id.* at 11. Mr. Davis and I&M Witness John F. Torpey, AEPSC Director-Integrated Resource Planning, said the estimated life for Tanners Creek Plant Units 1-3 was shortened due to the Company's response to recently proposed USEPA national standards. *Id.* at 11; Torpey Direct, at 4-13. These witnesses indicated neither Tanners Creek Unit 4 nor Rockport's estimated retirement dates changed from the prior depreciation study. *Id.*

Mr. Davis said the composite rate for Cook Nuclear Plant increased from 1.16% to 1.74% mainly due to a $401 million increase in Cook's electric plant in service and a shorter estimated remaining life since the last depreciation study. He said the Cook Plant's estimated retirement dates did not change from the prior depreciation study. *Id.*

Mr. Davis said the composite rate for Hydraulic Production Plant increased from 1.44% to 2.27% due to a $2.8 million increase in Hydraulic Plant electric plant in service and a shorter estimated remaining life since the last depreciation study. *Id.* at 11-12.

Mr. Davis said the depreciation rate for Transmission Plant increased from 1.46% to 1.68% due to increases in the net salvage ratio for six accounts (accounts 352, 353, 354, 355, 356 and 358) which was partially offset by an increase in average service life for four accounts (accounts 353, 354, 355 and 358). He said an analysis of the $2,614,244 annual Transmission depreciation expense increase indicates that the net salvage ratio increase (1 minus the net salvage percentage) accounted for $3,960,132 of the increase and that other changes including the increase in average service life estimates for four accounts caused a $1,345,888 decrease. *Id.*

Mr. Davis said the depreciation rate for Distribution Plant increased from 2.44% to 2.84% due to increases in the net salvage ratio for eight accounts (accounts 361, 362, 364, 365, 368, 369, 370 and 373) and a decrease in the average service life for one account (account 370). The rate increase was partially offset by an increase in average service life for six accounts (accounts 362, 365, 367, 369, 371 and 373). *Id.* at 13. His review of the $5,505,034 annual Distribution depreciation expense increase shows the net salvage ratio increase accounted for $4,411,256 of the depreciation expense increase and other changes amounted to a $1,093,778 increase. *Id.*

Mr. Davis said the depreciation rate for General Plant increased from 2.41% to 3.00% due to increases in the net salvage ratio for five accounts (accounts 390, 391, 394, 397 and 398). His review of the $479,756 annual General Plant depreciation expense increase shows that the net salvage ratio increase accounted for $488,826 of the depreciation expense increase and other changes amounted to a $9,070 decrease. *Id.*

**B. <u>OUCC Case-in-Chief.</u>** OUCC Witness William W. Dunkel, Principal of William Dunkel and Associates, responded to Mr. Davis's testimony and pointed out several flaws in the I&M depreciation study. Mr. Dunkel is a depreciation expert with a degree in engineering. Mr. Dunkel's recommended depreciation rates were presented in Attachment WWD-1. He recommended an increase in annual depreciation expense of $16.3 million on a total Company basis using depreciable plant balances at December 31, 2010, or $20.4 million less than the annual increase proposed by I&M. Dunkel Direct, at 6-7.

In calculating his proposed depreciation rates, Mr. Dunkel used June 2015 as the expected retirement date for Tanners Creek Units 1-3, based on the fact that the PJM web site indicates that I&M has requested "6/1/2015" as the "Deactivation Date" of those units. Thus, Mr. Dunkel testified, Mr. Davis used the incorrect retirement date of 2014.

Mr. Dunkel's proposed depreciation rates excluded the retirements, gross salvage, and cost of removal amounts associated with the Cook Unit 1 turbine replacement. *Id.* at 7, 10. Mr. Dunkel noted that gross removal related to the U1 Turbine Repair was incorrectly not excluded from the net salvage analysis used in I&M's depreciation study. He also pointed out that the retirements related to the U1 Turbine Repair were not removed from either the net salvage analysis or the interim retirement ratio calculations used in the I&M depreciation study.

Mr. Dunkel recommended adjusting the "Conceptual Demolition Cost Estimates" for Tanners Creek and Rockport Unit 1 based on the actual costs incurred to date to demolish I&M's Breed Plant. Mr. Dunkel explained that in 2005 I&M filed with the Commission the demolition "Conceptual Cost Estimates" prepared by Mr. Bertheau, a Senior Vice President with Sargent & Lundy$^{LLC}$ ("S&L"), for three steam production plants: Tanners Creek, Rockport Unit 1, and Breed. I&M proposes that the demolition costs for Tanners Creek and Rockport Unit 1 as estimated and updated by Mr. Bertheau be included in the depreciation calculations for recovery from ratepayers. However I&M recently completed the actual demolition of the Breed Plant and the actual cost to demolish the Breed plant was less than 40% of the Conceptual Cost Estimate. Mr. Bertheau's "Estimated Net Demolition Cost Estimate" was $28,633,000 for the Breed plant. The actual net demolition cost was $10,766,584. *Id.* at 11. He stated that the Conceptual Cost Estimates provided by I&M for the Rockport Unit 1 and Tanners Creek plants are not representative of the actual cost to demolish a steam production plant because the actual cost to demolish the Breed Plant was significantly less than Mr. Bertheau's Conceptual Cost Estimate for the Breed Plant demolition.

Mr. Dunkel recommended not inflating demolition costs to 2044 (for Rockport 1) or 2030 (for Tanners Creek Unit 4) price levels since the charges to current ratepayers will be collected in current dollars, and not collected in the lower-value year 2044 or 2030 dollars. Mr. Dunkel pointed out that Mr. Bertheau's estimate for I&M's share of demolition of Rockport 1 is $34,941,600 but when Mr. Davis inflated it to 2044 dollars it grew to $77,527,962. Mr. Dunkel stated that this inflation of demolition costs causes depreciation rates that are not cost based, because the value of the dollars I&M proposes to collect from its ratepayers today is different from the value of the future dollars I&M used to calculate demolition cost it included in its proposed depreciation rates. The dollars I&M proposes to collect today are more valuable than the dollars it used to calculate the amount of the inflated demolition cost and, as such, inflation should be removed from the calculation of the demolition costs. *Id.* at 17, 7-11.

Mr. Dunkel recommended removing the Breed Plant terminal removal costs and terminal salvages from the "interim" net salvage analysis prior to calculating the steam production depreciation rates to avoid double recovering the terminal removal costs. *Id.* at 8, 21-22. Mr. Dunkel noted that the inclusion of terminal removal costs in the interim removal cost overstates the depreciation rate.

Mr. Dunkel recommended discontinuing the interim retirements of Tanners Creek Units 1-3 after their retirement since the annual dollar amount of the interim retirements for the Tanners Creek plant will decrease after Units 1-3 are no longer in service and therefore no longer creating interim retirements. *Id.* at 8, 23. Mr. Dunkel's calculations reflected the fact that most common facilities (in addition to Unit 4) will still be in service after Tanners Creek Units 1-3 are retired. *Id.* at 8, 23-24.

Mr. Dunkel recommended keeping common equipment at Tanners Creek in service until the last unit retires. Mr. Dunkel testified that Mr. Davis's calculations assume that much of the Tanners Creek common equipment will retire when Units 1-3 retire. Mr. Dunkel noted that this is in error because the facilities that unload barges or handle coal cannot retire until the last unit (Unit 4) retires. *Id.* at 24.

Mr. Dunkel recommended continuing to use the current net salvage factors as used in the depreciation rates that the Commission approved in Cause No. 43231 for the Transmission, Distribution, and General Plant accounts. Mr. Dunkel testified that he made this recommendation because he noted that an inconsistency between the gross salvage and cost of removal amounts reflected in I&M's depreciation study and the data reflected in I&M's FERC Form 1 casts doubt on the reliability of the salvage data used in Mr. Davis's depreciation study. *Id.* at 24-33. Mr. Dunkel noted that for the non-production plant accounts the proposed I&M increases are almost entirely caused by changes in net salvage, which makes the accuracy of the net salvage data important.

Mr. Dunkel demonstrated that in the years 2005-2010 the total gross salvage that Mr. Davis used as a starting point for his depreciation study is less than half the total gross salvage reported in FERC Form 1, and the amount of gross salvage that Mr. Davis actual counted ($31 million) is approximately one-fourth of the gross salvage reported ($124 million) on FERC Form 1. As an explanation for the discrepancy Mr. Davis noted that retirement work in progress isn't removed from FERC Form 1 but is from his data. Mr. Dunkel went on to discuss that the FERC Form 1 does remove the retirement work in progress ("RWIP"). He showed that the gross salvage amount is actually $185 million and $61 million is removed as RWIP which leaves $124 million gross salvage after removal of RWIP. *Id.* at 29. Mr. Dunkel pointed out that for the years 2005-2010 I&M reconciliation of the differences between the gross salvage shown on FERC Form 1 and the gross salvage used in the depreciation study depend on using RWIP amounts which are significantly different than the RWIP amounts actually shown in the FERC Form 1 data. *Id.* at 31.

Mr. Dunkel testified that there are also discrepancies between the cost of removal used in Mr. Davis' study and the amounts listed on FERC Form 1, but the discrepancies in the cost of removal are less than in the salvage, so they do not fully offset. Mr. Dunkel demonstrated that for the years 2005-2010 the amount of gross salvage used in Mr. Davis's study was $92 million less than reported in FERC Form 1, but the cost of removal used in Mr. Davis's study was only $31 million less than reported in FERC Form 1, a discrepancy in net salvage of $61 million. Mr. Dunkel stated that understating the gross salvage increases the depreciation rates and the amount that was used in Mr. Davis's depreciation study is significantly lower than the gross salvage reported in FERC Form 1. *Id* at 32-33. Mr. Dunkel also raised a concern that Mr. Davis's workpapers indicate that only cash salvage, instead of all gross salvage was reflected in his depreciation study. Mr. Dunkel testified that using only cash salvage in a depreciation study understates the total amount of salvage. Cash salvage excludes the gross salvage that occurs when the utility retains its retired equipment for reuse elsewhere. *Id.* at 34-37.

**C. <u>IG Case-in-Chief.</u>** IG Witness James T. Selecky, Managing Principal of Brubaker & Associates, Inc., recommended that I&M's proposed depreciation rates be reduced to exclude the effects of including a contingency factor in the demolition cost estimates. Selecky Direct, at 7-8. He testified that the contingency factor does not represent a true cost and therefore should be excluded from the decommissioning cost estimates. *Id.* at 8. Mr. Selecky urged the Commission to give weight to the potential value of the steam production sites and utilize that value to eliminate the proposed contingency factors. *Id.* at 9.

Mr. Selecky recommended that the final decommissioming escalation rate used in the decommissioning cost estimates be reduced from the proposed 2.5% to 2.2%. He stated that the 2.2% rate was based on more current information from the U.S. Energy Information Administration's Annual Energy Outlook 2012 Early Release Overview Consumers Price Index for the period 2010-2035. *Id.* at 13.

He recommended that the life of Tanners Creek Units 1, 2 and 3 be extended by two years and that the life span of Rockport Unit 1 be increased from 60 to 65 years for purposes of calculating the depreciation rates. *Id.* at 15, 16 and 19.

Mr. Selecky's proposed revisions to I&M's depreciation parameters (life span and final net salvage ratios) would reduce the proposed depreciation expense by $7.794 million. *Id.* at 3, 6.

**D. <u>I&M Rebuttal.</u>** I&M Witness Bertheau discussed Mr. Selecky's recommendation to exclude contingency factors associated with the scrap value, material, labor and indirect costs in the demolition conceptual cost estimates. Bertheau Rebuttal, at 5. Mr. Bertheau said the S&L demolition cost estimates for the Rockport and Tanners Creek plants were developed through site-specific analysis. *Id.* at 6-7. He suggested the cost estimates were prepared consistent with prudent industry practices and previous S&L demolition estimates. He said S&L's experience with demolishing parts of existing facilities to modify plant configurations for accommodating new equipment provided a basis for the estimating procedures used to prepare the demolition cost estimate studies for I&M. *Id.* at 7.

Mr. Bertheau said there are reasons why it is appropriate to include contingency factors. Bertheau Rebuttal, at 9. He said one reason is that power plants are in a continuous state of configuration change over their operating lives. He said a demolition study, however, must be made at a certain point in time at which it is not possible to anticipate with precision all the ways the plant will be modified over time as a result of this dynamic. He said significant changes to power plant configurations over the life of the plant are associated with changing environmental regulatory requirements. He said the change in and issuance of final and proposed environmental regulations have and will result in billions of dollars in increased infrastructure and new buildings and equipment being added to power plants in order to control emissions. Mr. Bertheau said the nature and scope of future plant configuration changes are not defined at this time. He suggested positive contingencies in demolition cost estimates are necessary to account for the increases in plant facilities that will occur between the time the cost estimates were developed and the end of life of the facility. He said contingencies capture unknowns and future changes. He suggested the contingencies used in the demolition estimates in this case are reasonable and similar to the factors approved by the Commission in Northern Indiana Public Service Company ("NIPSCO") Cause No. 43526. Bertheau Rebuttal, at 9; *see also* Davis Rebuttal, at 8.

Mr. Bertheau claimed Mr. Dunkel's recommendation that the S&L demolition cost estimates for Tanners Creek and Rockport Unit 1 should be adjusted based on the actual cost data from the Breed facility demolition. Bertheau Rebuttal, at 5. Mr. Bertheau theorized that Mr. Dunkel's logic in making such a recommendation is incorrect in assuming that Breed's demolition can be compared to both Tanners Creek and Rockport. Mr. Bertheau said power plants each have unique facility configurations and therefore costs for demolition can vary between facilities. *Id.* at 7. He said the Rockport and Tanners Creek demolition cost estimates were developed as site specific and cannot be adjusted based on the cost of demolition of a completely different plant. *Id.* at 8. He suggested the S&L study substantiates the site-specific demolition, excavation, and disposal characteristics of each I&M site and claimed each facility was evaluated on an individual basis, due to inherent differences, to ensure that prudent and reasonable cost estimates were provided for the most-likely demolition scenario. *Id.* at 6-7. He suggested the assumptions used to prepare the demolition cost estimates were consistent with industry practices and previous S&L demolition estimates. He claimed S&L's experience with demolishing parts of existing facilities to modify plant configurations for accommodating new equipment also provided a basis for the estimating procedures used to prepare the demolition cost estimate studies for I&M.

He claimed the demolition techniques and crew mixes assumed in the S&L cost estimates are typical techniques used in the industry based on S&L's years of experience serving the electrical power generation industry and also reflected input from a major demolition contractor, U.S. Dismantlement. *Id.* at 8. He suggested the techniques and approaches for demolition reflected in the study are based on the experiences of individuals who have competitively bid and successfully executed the subject work for many years. *Id.* Mr. Bertheau said controlled demolition techniques were specified in the study at locations where critical infrastructure would be at risk of serious damage by use of uncontrolled demolition. Mr. Bertheau suggested the controlled demolition techniques assumed in the S&L cost estimates are proven in the industry which will protect critical infrastructure and maintain its viability for future use. *Id.* at 9.

Mr. Davis discussed Mr. Selecky's recommendation to reduce the decommissioning cost escalation rate from 2.5% to 2.2%. Davis Rebuttal, at 4. Mr. Davis claimed Mr. Selecky's logic for changing the inflation percentage is that the Commission should use more current information than that published in the Livingston Survey dated December 9, 2010. *Id.* at 5. Mr. Davis said the updated Livingston Survey dated December 8, 2011 continues to use the 2.5% inflation factor published in the 2010 survey. Mr. Davis said other current measures of inflation were higher than 2.5% and allegedly support I&M's use of a 2.5% inflation factor. Davis Rebuttal, at 5-6.

Mr. Davis also discussed Mr. Selecky's recommendation that the Commission give recognition to the potential value of the steam production sites and utilize that value to eliminate the proposed contingency factors. Davis Rebuttal, at 6. He suggested Company-owned land that may or may not be used for a future generating site is non-depreciable property and as such should never be considered in a depreciation study. *Id.* at 6. He claimed I&M has no current plans to re-use the existing generating sites so the future benefit is speculative. He suggested any existing structures that remain on the generating plant site and continue to be used and useful would be on the Company's books at original cost less accumulated depreciation and included in rate base. *Id.* at 6-7.

I&M Witness Torpey said in his rebuttal testimony that I&M's proposed retirement date for Tanners Creek Units 1-3 is primarily based on the cost to comply with the Mercury and Air Toxics Standards ("MATS") Rule which was finalized after I&M's case in chief was filed in this Cause, and, to a lesser extent, the proposed Coal Combustion Residual ("CCR") regulations expected to be finalized in 2013. Torpey Rebuttal, at 11. Mr. Torpey discussed Mr. Selecky's suggestion that the MATS Rule may be reversed should not influence the proposed retirement date for the Tanners Creek Units 1-3. He suggested Mr. Selecky's belief that the implementation of these rules might be delayed has no foundation. *Id.* at 5. However, given that the MATS Rule became effective later than the date estimated in Mr. Torpey's direct testimony, I&M agreed that the proposed retirement of June 1, 2015 should be adopted for planning purposes. *Id.* at 11. However, Mr. Davis claimed the change in the planned retirement date would not make a material difference in the depreciation rates. Mr. Davis suggested the new depreciation rates are based on a December 31, 2010 study and the recommended rates would not be effective until late in 2012. As a result there will be a lag in implementing new depreciation rates of more than 1 and ½ years from the date of the depreciation study and the lag would compensate for Mr. Dunkel's proposed June 2015 retirement date. Therefore, Mr. Davis claimed I&M's depreciation rate calculation for Tanners Creek Units 1-3 should not be adjusted for a June 2015 retirement date. Davis Rebuttal, at 9.

Mr. Torpey discussed Mr. Selecky's recommendation to extend the useful life of Rockport Unit 1 from 60 years to 65 years. He said the remaining service life of a power generating facility is generally correlated to the level of maintenance and routine component replacement that is undertaken through the life of the unit. Mr. Torpey claimed there is no relationship between the remaining service lives of Rockport Unit 1 and Tanners Creek Unit 4 or the coal plants listed on IG Exhibit JTS-2 to Mr. Selecky's testimony. *Id.* at 6-7. Mr. Torpey suggested Mr. Selecky did not present an assessment of the condition or operating characteristics of Rockport Unit 1 that would lead to a conclusion that a longer life is warranted. *Id.* at 8.

Mr. Davis agreed that an adjustment should be made to eliminate the retirements and cost of removal along with the salvage (which was already eliminated from the Company's analysis) related to the Cook Unit 1 turbine replacement but disagree with Mr. Dunkel's calculation. Davis Rebuttal, at 10.

Mr. Davis discussed Mr. Dunkel's assertion that the conceptual demolition study amounts for Tanners Creek Units 1-3 and Rockport Unit 1 should not be adjusted for inflation. He said the regulatory rationale for setting depreciation rates on a straight line basis over the remaining life of the property is to promote intergenerational equity and appropriately match cost to the provision of service. *Id.* at 11. Mr. Davis offered citations to Commission orders, which he claimed the Commission has accepted the calculation of terminal demolition costs inflated to their retirement date, including *PSI Energy Inc.*, Cause No. 42359 (IURC 5/18/2004) and *NIPSCO*, Cause No. 43526 (IURC 8/25/2010). Mr. Davis said I&M escalated terminal demolition costs for its steam generating stations in Cause No. 39314. He said in Cause No. 42959, in which I&M's current depreciation rates were established, I&M chose not to escalate the terminal demolition costs, but did so to "eliminate most areas of controversy to facilitate a more expedient decision from the Commission." Davis Rebuttal, at 13. Mr. Davis suggested I&M's inflation of the S&L terminal demolition estimates implements a cost-based approach because the future estimate of terminal demolition costs more precisely determines the total net cost of demolishing the plants. *Id.* at 13.

Mr. Davis said interim net salvage relates to retirement costs for property that is retired prior to the final terminal retirement of the property. Mr. Davis suggested it is important to include an analysis of interim retirements in a depreciation study since all of the property that is initially placed in service will not last until the final retirement date. Davis Rebuttal, at 14. Mr. Davis said some terminal (final) demolition costs should be excluded from the interim net salvage calculation. Mr. Davis claimed that Mr. Dunkel's adjustment is incomplete because the calculation included salvage and removal costs related to the Breed generating station and ignores the Twin Branch Steam Plant's original cost retirement in 1981. *Id.* at 14-15. Mr. Davis suggested that when the proper adjustment is made the net salvage percentage equals the percentage calculated in the Company's depreciation study. *Id.* at 15.

Mr. Davis agreed that the calculation of depreciation rates for Tanners Creek Units 1-3 should be adjusted to reduce interim retirement amounts after the terminal retirement of Tanners Creek Units 1-3 and set forth this revision on Petitioner's Exhibit DAD-R6. Davis Rebuttal, at 16.

Mr. Davis discussed Mr. Dunkel's proposal to decrease the steam production rates to account for common plant, which will remain on the Company's books until Unit 4 retires. Davis Rebuttal, at 17. He said I&M does not maintain a property record for Tanners Creek Plant by unit, so an estimated retirement amount was calculated for Units 1-3 based on an allocation using megawatt capacity. *Id.* at 17. He claimed neither Mr. Dunkel nor the Company has gathered adequate information to calculate or determine if a significant amount of common plant should be deducted from the estimated retirement of Units 1-3 to calculate depreciation rates. Mr. Davis said when the Tanners Creek Units 1-3 are retired, the Company will perform a detailed study to determine the proper amount of original cost to retire and any over or under accrual of depreciation will be reflected in future depreciation rates by using the remaining life technique. Davis Rebuttal, at 17.

Mr. Davis discussed Mr. Dunkel's proposal not to update the net salvage factors used for Transmission, Distribution and General Plant. Davis Rebuttal, at 18. Mr. Davis claimed I&M's depreciation study used the same procedures and techniques to gather and report salvage and removal amounts and calculate percentages for Transmission, Distribution and General Plant as was used in its filing in Cause No. 42959. *Id.* at 18-19. Mr. Davis suggested he did not use the same salvage data amounts as presented on the Company's FERC Form 1 because the FERC Form 1 amounts include retirement work in progress amounts ("RWIP"), which should not be included in depreciation study calculations. Mr. Davis claimed RWIP is accumulated on work orders similar to construction work in progress. He said while the removal work is being performed, RWIP charges and salvage amounts continue to be accumulated until the work is done and the work order is closed. *Id.* at 19-20. He said when the work order is closed, an original cost retirement is recorded and only then is it possible to match retirements, salvage and removal in the depreciation study. Mr. Davis claimed it would be incorrect to include RWIP in the depreciation study because this would require salvage and removal to be divided by as yet to be booked original cost retirements. *Id.* at 20. Mr. Davis disagreed with Mr. Dunkel's discussion of the FERC Form 1 data and suggested the amounts in I&M's depreciation study and the FERC Form 1 data both come from the financial records of the Company that are reviewed by I&M and AEP management and external auditor Deloitte & Touche. *Id.* at 20. Mr. Davis claimed the depreciation study amounts were gathered in a consistent fashion with prior depreciation studies. *Id.* at 21. Mr. Davis theorized that Mr. Dunkel's calculation is in error because it relied on a data request response that reflected RWIP transferred to in service instead of the data request response that provided the full RWIP balance. *Id.* at 21. Mr. Davis attempted to present a reconciliation of the amounts of retirements, salvage and removal reported in the FERC Form 1. *Id.* at 20-22.

Mr. Davis also discussed Mr. Dunkel's testimony that the net salvage calculations should be considered unreliable due to a label in one of Mr. Davis' workpapers. *Id.* at 22. He claimed I&M did not exclude non-cash salvage from the depreciation study but that the reference to "Salvage Cash" in the workpapers was merely an incorrect label. He claimed the "Salvage Cash" amount was not just cash salvage but included in the total amount of salvage booked for the period of time in question. *Id.* at 22.

Because of his concerns about the data used to calculate net salvage, Mr. Dunkel recommended the Commission continue to use the net salvage factors for Transmission, Distribution and General Plant from Cause No. 43231 in lieu of the factors calculated in the current depreciation study. Mr. Davis disagreed. Davis Rebuttal, at 23. He attempted to defend the reliability of the salvage and removal data used in the depreciation study. He prepared an updated net salvage factor calculation adding year 2011. He said only two net salvage factors were less negative (accounts 355 and 362) and eleven factors slightly more negative as a result of that update. *Id.* at 24-25.

**E. <u>Commission Discussion and Findings.</u>** I&M's present depreciation rates for its electric utility plant are based on a 2004 depreciation study accepted in a settlement agreement in Cause No. 43231 approved on an interim basis in Cause No. 43231 and finalized in Cause No. 43306. The existing depreciation rates for Rockport's ACI system and Tanners Creek's SNCR were established in 2009 under Cause No. 43636 related to the use of clean coal technology. We discuss the disputed issues regarding I&M's proposed depreciation rates below.

(I) <u>Escalation Rate.</u> I&M proposes to increase Mr. Bertheau's demolition cost estimates by 2.5% annual inflation to year 2044 price levels for Rockport 1 and to year 2030 prices levels for Tanners Creek. IG Witness Selecky objected to the rate of inflation assumed for steam production plant. OUCC Witness Dunkel disagreed with the use of future inflation adjusted terminal cost of removal amounts and instead recommended that the demolition cost used in determining the amount to be charged to current ratepayers be calculated in the same current value of dollars that would be collected from ratepayers.

We find Mr. Dunkel's explanation informative. Mr. Dunkel states that if ratepayers each year are responsible for 1/50$^{th}$ of the demolition cost, then if the demolition cost is \$35 million in current dollars, the current year ratepayers will have paid their fair share if they pay 1/50$^{th}$ of \$35 million. If that same demolition will cost \$77 million in year 2044 dollars, because of the lower value of the year 2044 dollars, Mr. Dunkel says the year 2044 ratepayers will have paid their fair share if they pay 1/50$^{th}$ of \$77 million. The year 2044 ratepayers may pay more dollars, but that is because they are paying using dollars that are worth about half what today's dollars are worth. Tr. W-110-111. By comparison the I&M method calculates the cost in future dollars for purposes of the current depreciation study. In this illustration the I&M treatment would make the current year ratepayers pay 1/50$^{th}$ of \$77 million, which is the demolition cost in year 2044 dollars.

We find that current customers, who are paying using current dollars, will pay their fair share if the demolition cost is determined in current dollars. Assuming a 50 year life, if the demolition cost is \$35 million in current dollars, the current year ratepayers will have paid their fair share if they pay 1/50$^{th}$ of \$35 million. On the other hand if the current year ratepayers pay 1/50$^{th}$ of \$77 million (which is the demolition cost in year 2044 dollars) they would be paying more than their fair share. We do not believe that increasing the demolition costs for the lower value of the future dollar, while it will be collected from ratepayers paying with the higher value current dollar, produces the most reasonable charge to ratepayers. Further we note that I&M does not currently have future inflation of demolition costs built into currently approved the depreciation rates. We find no compelling reason to deviate from this and the depreciation rates we approve do not include future inflation of demolition costs.

Based upon projections of future inflation set forth in the Annual Energy Outlook 2012 Early Release Overview, Mr. Selecky reduced Mr. Davis's recommended future inflation rate. We decline to decide this issue as we have already agreed with OUCC witness Mr. Dunkel and have removed future inflation from the terminal salvage and removal amounts.

(2) Demolition Conceptual Cost Estimates.

(a) Contingency Factor and Non-Depreciable Land. Mr. Bertheau includes a contingency factor in his demolition cost estimates. Mr. Selecky argued that the contingency should be eliminated as unreasonable, or at a minimum offset by the value of the land of the steam production sites over the value of raw land. Selecky Direct at 8-9. Mr. Dunkel proposes that the demolition costs for the Tanners Creek and Rockport plants be based on the actual demolition costs for the Breed plant, adjusted for the differences among the plants. In the following section we find that the Breed evidence shows that the demolition cost estimates that Mr. Bertheau presents overstate the actual cost of demolishing a steam production plant. Therefore in the following section we find the demolition costs for the Tanners Creek and Rockport plants are to be significantly reduced from the amounts Mr. Bertheau proposed, based on the actual demolition experience of the Breed plant. If we were to further reduce these demolition costs based on "contingencies" we would have demolition costs less than indicated by actual experience, which we decline to do.

Mr. Davis stated that Company-owned land that may or may not be used for a future generating site is non-depreciable property and as such should never be considered in a depreciation study. Davis Rebuttal, at 6. He stated that I&M has no current plans to re-use the existing generating sites so the future benefit is speculative. In our decision in Cause No. 43526, issued August 25, 2010, we rejected a similar proposal made by Mr. Selecky with respect to NIPSCO's studies. Here Mr. Selecky did not identify a dollar value associated with the value of land and as a result there is no evidence in the record to guide us in determining whether this would produce a material difference in the depreciation rates or be a reasonable trade-off for the contingency, assuming for the sake of argument it would even be proper to treat a non-depreciable asset like land as salvage. In our Order in Cause No. 43526, we found that "[n]o evidence was presented that this Commission has ever used the value of land as an offset to an asset's cost of removal. In fact, Mr. Selecky did not identify to us any decision of any regulatory commission accepting his position regarding land and the contingency." Mr. Selecky has failed to provide evidence sufficient to further reduce the demolition costs below the level indicted by the actual Breed demolition experience.

(b) Revisions Based On Breed Plant Actual Demolition Cost. OUCC Witness Dunkel testified that the demolition conceptual cost estimates conducted by S&L should be adjusted based on the Breed Plant actual demolition cost.

Mr. Dunkel explained that in Cause No. 42959 I&M filed with the Commission the demolition "Conceptual Cost Estimates" prepared by Mr. Bertheau for three steam production plants: Tanners Creek, Rockport Unit 1, and Breed. In this proceeding Mr. Bertheau has updated these prior estimates for Tanners Creek and Rockport Unit 1. I&M proposes that the demolition costs for Tanners Creek and Rockport Unit 1 as estimated by Mr. Bertheau be included in the depreciation calculations for recovery from ratepayers. These demolition estimates assume the more expensive top down method. Mr. Dunkel noted that the actual cost to demolish the Breed plant (Unit 1) was $10,766,584 and the Conceptual Cost to demolish the Breed plant was $28,633,000. The actual cost to demolish the Breed plant was approximately 40% of Mr. Bertheau's Conceptual Cost to demolish the plant.

Mr. Dunkel used the fact that the actual Breed demolition costs were only 40% of Mr. Bertheau's estimate to similarly reduce the Conceptual Cost Estimates for Rockport Unit 1 and Tanners Creek to 40% of Mr. Bertheau's estimates. The record reflects that there is no reason to believe that the method of demolition used at the Breed plant cannot be used at either Tanners Creek or Rockport. The S&L study reflects the use of extremely expensive top down or controlled demolition techniques at locations that do not require such techniques. The top down method that Mr. Bertheau assumed is very expensive because it assumes workers will take the stack, boiler and boiler building apart piece by piece and then lower these pieces to the ground. On page 15 of the I&M Proposed Order I&M would have us reject the use of explosives out of alleged concern about "sensitive switchyard equipment." However there is no witness that presented this concern in testimony. Mr. Bertheau, who responded to Mr. Dunkel's demolition testimony, made no reference to sensitive switchyard equipment anywhere in his rebuttal testimony. During cross examination Mr. Dunkel stated that when a plant is dismantled the switchyard needs to be protected from vibrations, but he pointed out that the Rockport plant is in a seismic active area and he has to assume that the company has installed breakers that are vibration tolerant. Tr., W-104. We agree with Mr. Dunkel that the switchyard in a seismic active area should be able to withstand the demolition techniques used at the Breed plant, and we are not aware of any I&M testimony or exhibits to the contrary. We also find no evidence in the record that dropping the stack at the Breed plant with explosives or pulling over the Breed boiler building had any adverse impact on the nearby switchyard. Mr. Dunkel correctly noted that the type of demolition proposed by S&L (top down) is more expensive than other methods of demolition as evidenced by the actual cost to demolish the Breed plant. The record reflects that Breed was a stand-alone unit in a relatively uninhabited area, but Mr. Dunkel noted that it appears that Tanners Creek and Rockport plants do not appear to have any homes or other non-utility structures close enough to make it impossible to use the demolition techniques from the Breed plant. Mr. Dunkel also noted that any nearby power plant structures are not valid concerns because all steam production units in the plant and the common plant will be demolished at the same time. Dunkel Direct at 15. In practice the demolition contract goes to the lowest cost qualified bidder, which means the demolition contractor that uses the most cost effective methods will be doing the actual demolition. Tr. W-47.

We agree with Mr. Dunkel and find the evidence shows that it is less labor intensive and less costly to bring the stack to the ground with explosives and to bring the boiler building to the ground by pulling it over, as opposed to workers taking these structures apart piece by piece and then lowering those pieces to the ground. The Breed evidence shows that the demolition cost estimates that Mr. Bertheau presents overstate the actual cost of demolishing a steam production plant. For purposes of determining the demolition costs to collect from the ratepayers through the depreciation rates, the more cost effective methods of demolition are appropriate and therefore the OUCC provided estimates should be utilized for Rockport and Tanners Creek.

<u>(3) Estimated Service Lives.</u>

(a) <u>Tanners Creek.</u> Both Petitioner and the OUCC agree that the "Deactivation Date" for these units is June 2015. Since the time Mr. Davis prepared his depreciation study the expected retirement date for these units has been moved from 2014 to 2015. However in his rebuttal Mr. Davis chose not to use the 2015 retirement data and continued to propose depreciation rates based on a 2014 retirement date. He states there will be a 1 and ½ year lag between the preparation of the study and the implementation of the new depreciation rates which would more than compensate for the change in retirement date. We find that this "lag" argument is not persuasive. First, the 1 and ½ year lag Mr. Davis discussed started at the date of the data in his study, which is 10/31/2010 and it would be inappropriate for the Commission to establish retroactive depreciation rates. Mr. Davis knew there would be about a 1 and ½ year lag and he thought the retirement date was in 2014. The lag is still the same, but the expected retirement date has changed to 2015, so that change in retirement date must be incorporated into the depreciation rates. Tr. W-105, lines 18-25. In addition we would note that I&M does collect depreciation expense on these plants during the 1 and ½ year of lag; the existing depreciation rates still apply. Tr. W-106, lines l- 18 to W-107, lines l-2.

IG provided testimony from Mr. Selecky recommending a retirement date of December 31, 2016. Both Petitioner and Mr. Selecky have provided testimony explaining that the retirement date is primarily driven by certain EPA regulations that have either recently become effective or are currently pending. These include: the Mercury and Air Toxics Standards ("MATS") Rule which became effective on April 16, 2012; the Cross State Air Pollution Rule ("CSAPR") which was finalized and published in the Federal Register on August 8, 2011 and ultimately stayed on December 30, 2011 by the U.S Court of Appeals for the District of Columbia Circuit; and the Coal Combustion Residual ("CCR") regulations requiring modifications to certain ash handling systems and ash ponds by 2018, which are still scheduled to be finalized in early 2013. We find Mr. Selecky's proposed extension of the Tanners Creek Units 1, 2 and 3 service lives should be rejected.

I&M and OUCC agree that the planned retirement for Tanners Creek Units 1, 2, and 3 has shifted to June, 2015, and as such we find it necessary to revise the new depreciation rates to incorporate a terminal retirement date of June, 2015 for these units.

(b) Rockport Unit 1. Witness Selecky recommends extending the useful life of Rockport Unit 1 from 60 years to 65 years, based on I&M's use of a depreciable life of 66 years for Tanners Creek Unit 4 and the depreciable lives of various other coal plants, many of which exceed 60 years. IG Exhibit JTS-2. However, Mr. Selecky has failed to show a direct relationship between Tanners Creek Unit 4 or any of the other coal-fired units referred to in his exhibit and Rockport Unit 1 sufficient to show that the life spans of those other units are directly applicable to Rockport Unit 1. The service life of a power generating unit can vary depending on the plant owner's determination, at times when a significant investment is required to maintain a unit's operation, as to whether the least cost long-term solution is to repair/modify or retire/replace the asset. Those decisions must take into account both existing as well as projected future operating conditions and constraints. A plant owner can only make decisions based on the best available information at the time.

While Mr. Selecky suggests it is possible that the Rockport Unit 1 will have a service life that exceeds 60 years, it is equally plausible that the service life will be less than 60 years, especially when developing EPA regulations regarding carbon emissions are taken into account. Our goal is to depreciate Rockport Unit 1 over its service life. Here, the record does not reflect evidence of a condition or operating characteristics of Rockport Unit 1 that would reasonably lead to a conclusion that a longer life for the Rockport Unit 1 is warranted. Accordingly, we decline at this time to revise the life span of this coal plant from 60 years to 65 years.

(4) Net Salvage Factors. Petitioner and the OUCC disagree regarding the net salvage factors to be used for Transmission, Distribution and General Plant. OUCC Witness Dunkel contends that the gross salvage and cost of removal amounts used in Petitioner's depreciation study are unreliable because they are inconsistent with the information in I&M's FERC Form 1. Mr. Dunkel recommended that we continue to use the net salvage factors reflected in rates previously approved in Cause No. 43231 in lieu of the factors calculated in the current depreciation study. Mr. Dunkel demonstrated that virtually all of the over $8 million increase that Mr. Davis proposes in the Transmission, Distribution, and General Plant categories resulted from the fact that the net salvage factors as calculated by Mr. Davis are significantly different than the net salvage factors calculated in the prior I&M depreciation study.

Mr. Dunkel presented compelling evidence that this significant change in Mr. Davis's net salvage is not the result of an actual shift in the actual net salvage. Mr. Dunkel demonstrated that in the year 2009, the gross salvage reported by I&M in FERC Form 1 is $104 million. This $104 million is the amount of gross salvage credited into the accumulated depreciation reserve in 2009 in FERC Form 1. For this same year in his depreciation study Mr. Davis used less than $7 million as his gross salvage for all accounts combined. This is a $97 million dollar understatement of gross salvage for the year 2009 in Mr. Davis' study. Mr. Dunkel demonstrated that similar discrepancies existed in total during the years in which Mr. Davis was responsible for the data used in his depreciation study (2005-2010). Mr. Dunkel demonstrated that for the years in which Mr. Davis had prepared the data, the total gross salvage included in his study was $55 million on a total company basis, but in its FERC Form 1s I&M had reported a total of $124 million gross salvage for those same years. This $124 million is after the RWIP amount was removed. In these years, Mr. Davis included only $55 million of gross salvage in his depreciation study, which is less than one-half of the gross salvage that I&M reported over the same years in its FERC Form 1s. These large and consistent discrepancies cause us to agree with Mr. Dunkel that the data relied upon by Mr. Davis in his depreciation study is unreliable.

I&M Witness Davis has not explained the difference between the data contained in the depreciation study and I&M's FERC Form 1 to our satisfaction. Mr. Davis tried to explain this discrepancy by claiming that the data I&M files in its FERC Form 1s is "like a half-baked pie." Tr. F-24-25. However an officer of I&M, signs a statement that certifies the FERC Form 1 information is correct. If I&M cannot agree internally whether its gross salvage is $104 million or $7 million in 2009, we cannot reasonable rely on that gross salvage data as the basis for increasing the depreciation rates. Mr. Davis also claims that the difference relates to the fact that the FERC Form 1 reported data reflects RWIP amounts. However the FERC Form 1 numbers Mr. Dunkel used to demonstrate this difference are the FERC Form 1 numbers after the RWIP amounts have been removed. For the years 2005-2010 the FERC Form 1 gross salvage amounts that includes RWIP total $185 million. However on a subsequent line the FERC Form 1 removes the RWIP amount, which totals $61 million. After RWIP is removed the gross salvage totals $124 million in FERC Form 1. In his study Mr. Davis included only $55 million of gross salvage as his starting point, and further decreased it from there. Dunkel Direct at 29. The exclusion of the total gross salvage amounts reported on FERC Form 1 caused Mr. Davis's proposed depreciation rates to be overstated. This overstatement of the depreciation rates has reinforced our opinion that the salvage data used by Mr. Davis in his depreciation study is unreliable.

Mr. Dunkel presented further evidence that the net salvages Mr. Davis used were incorrect. The I&M workpapers contained in Attachment WWD-22 to Mr. Dunkel's Direct testimony show the gross salvage amounts Mr. Davis included for the Transmission accounts are labeled as "Salvage Cash" and the gross salvage amounts Mr. Davis included for Distribution Plant accounts are "Salvage Cash." Using only "cash" salvage in a depreciation study understates the total amount of salvage. Cash salvage excludes the gross salvage that occurs when the utility retains its retired equipment for that utility's reuse elsewhere. We find that we have no definite way from the record to determine if this use of "Salvage Cash" is a mislabeling or further indicates understating of salvage, but it does give us additional concern over the reliability of the salvage data used by Mr. Davis in his depreciation study.

We find that I&M has not satisfied its burden of proof for the proposed changes in the net salvage factors in Distribution, Transmission and General Plant. Therefore the OUCC proposed depreciation rates for these categories, which use the existing Commission approved net salvage factors, are adopted.

(5) Reduction to Retirement Amounts for Tanners Creek Units 1-3 for Common Plant. The record shows that based on Megawatt capacity, Mr. Davis utilized retirements for approximately 50% of all investments at Tanners Creek when Tanners Creek Units 1-3 are expected to retire. This means that he retires approximately 50% of the rail road line and 50% of the equipment that unloads the barges. Mr. Dunkel proposed to revise I&M's steam production rates by decreasing the estimated common amount to be retired along with Tanners Creek Units 1-3 to account for common plant which will remain on the Company's books until Unit 4 retires. Mr. Dunkel testified that much of the common plant cannot retire until the last unit retires. We agree with Mr. Dunkel's revision of the steam production rates as the last unit still operating will require the use of the common plant until it retires.

(6) Exclusion of Salvage, Cost of Removal and Retirements for Cook Unit 1 Turbine Fire. Mr. Dunkel proposed that the salvage, cost of removal and retirements associated with the Cook Unit 1 turbine fire should be excluded from the depreciation study data. In rebuttal Mr. Davis agreed with Mr. Dunkel, except Mr. Davis provided a calculation slightly different from Mr. Dunkel's calculation. In his calculation Mr. Davis proposes to round to a different decimal place than that used by Mr. Dunkel. We agree with the parties that the salvage, cost of removal and retirements associated with the Cook Unit 1 turbine fire should be removed from the depreciation calculation. We find Mr. Dunkel's correction should be adopted.

(7) Terminal Demolition Costs in Interim Net Salvage Factor. Interim net salvage relates to retirement costs for property that is retired prior to the final terminal retirement of the property. It is important to include an analysis of interim retirements in a depreciation study since all of the property that is initially placed in service will not last until the final retirement date. In his depreciation study Mr. Davis removed the terminal retirement amount for the Breed plant from his interim net salvage data, but left the Breed terminal salvage and terminal cost of removal in his interim data. Mr. Dunkel removed the Breed terminal salvage and terminal cost of removal from his interim data. Both I&M and the OUCC agree that the terminal data should be excluded from the interim analysis. In rebuttal Mr. Davis provides a calculation in which he removes the original cost terminal retirement for another retired plant, Twin Branch, from the interim data, but then Mr. Davis makes no mention of excluding the Twin Branch terminal salvage and terminal cost of removal.

We find that the Breed terminal original cost retirement, terminal salvage and terminal cost of removal are to be excluded from the interim analysis. Therefore the we adopt the OUCC adjustment presented by Mr. Dunkel. We further find that before the next depreciation study is presented to the Commission I&M is to identify the amounts of the Twin Branch terminal original cost retirement, terminal salvage and terminal cost of removal, and exclude all of these Twin Branch terminal amounts from the interim net salvage analysis.

(8) Interim Retirement Revisions Related to Tanners Creek Units 1-3 Retirement. Mr. Dunkel noted that the interim retirements produced by Tanners Creek

Units 1, 2, 3, and 4 total $2,692,172 per year and that Mr. Davis included this amount per year even after Units 1, 2 and 3 are retired. In rebuttal Mr. Davis agreed that the calculation of depreciation rates for Tanners Creek Units 1-3 should be adjusted to reduce interim retirement amounts after the terminal retirement of Tanners Creek Units 1-3. We find that interim retirements for Tanners Creek should be reduced to account for the retirement of Units 1, 2 and 3. We accept the adjustment as provided by Mr. Dunkel.

(9) Ultimate Finding. We conclude that the OUCC's proposed depreciation rate changes as presented in Mr. Dunkel's testimony are reasonable, will provide the Company with a more appropriate and accurate depreciation accrual based upon current circumstances, and will better match the cost of I&M's plant in service with the periods expected to benefit. We find that the OUCC's depreciation rates should be approved and I&M is authorized to place into effect for accrual accounting purposes, the depreciation accrual rates set forth in the OUCC's case-in-chief. The approved depreciation rates result in an increase in annual depreciation expense to reflect the new rates of $16,290,171 on a total Company basis based on depreciable plant in-service at December 31, 2010.

**8. Petitioner's Rate Base.**

**A. Legal Requirements.** [NOTE - TOPICS ADDRESSED IN THIS SECTION OF PETITIONER'S PROPOSED ORDER ARE ADDRESSED IN OUCC'S PROPOSED ORDER EITHER IN SECTION 8D, "FAIR VALUE" and/or SECTION 9C, "FAIR RATE OF RETURN".]

**B. Original Cost.** The Indiana jurisdictional original cost of Petitioner's property used and useful in providing service to the public at December 31, 2011 is $2,185,361,368 (Petitioner's Exhibit A-S6, p. 1) and the proposed Indiana jurisdictional net original cost rate base was $2,391,632,939 calculated by Petitioner as follows:

| | |
|---|---|
| Net Plant At Original Cost | $2,185,361,368 |
| Other Post Employment Benefits ("OPEB") | $ 1,478,564 |
| 165 Prepaid Pension Expense | $ 61,691,738 |
| 253 Deferred Gain Rockport 2 Sale | $ (26, 201,384) |
| 151 Fuel Stock | $ 47,809,575 |
| 156 Other Materials & Supplies | $ 121,493,078 |
| Original Cost Rate Base | $2,391,632,939 |

Petitioner's Exhibit A-S6, p. 1. Notably, this rate base does not include Petitioner's investment of approximately $125 million in the new Cook Unit 1 turbine which was placed in service and became used and used utility property on October 26, 2011. We discuss this issue below.

OUCC Witness Michael D. Eckert, Senior Utility Analyst in the OUCC's Electric Division, proposed a net original cost rate base equal to $2,324,464,062. Eckert at 37. The difference from Petitioner's proposed net original cost rate base is that the OUCC (and SDI Witness Ralph C. Smith, Senior Regulatory Consultant at Larkin & Associates, PLL) proposed to exclude from rate base the prepaid pension asset and the OUCC proposed inclusion of materials and supplies based on a 13-month average as opposed to the actual balance as of March 31, 2011. The Commission's findings on the proposed adjustments to rate base which were disputed are discussed below.

(1) Cook Unit 1 Turbine.

(a) I&M Case-in-Chief. The Cook Unit 1 turbine replacement, which I&M asserted was a Major Project as that term is used in 170 I.A.C. 1-5-1(l), was installed during the refueling outage and placed into service on October 26, 2011. In his prefiled direct testimony, I&M Witness Michael H. Carlson, I&M Vice President - Site Support Services at Cook Plant, estimated the cost for the turbine replacement to be $139 million (Total Company). As set forth in the pre-hearing conference order in this case, I&M filed investment updates on a monthly basis. I&M stated in its Exhibit SMK-S1 that the Plant In Service balance for the project through April 30, 2012 was $125,683,529 (Total Company). Mr. Scott Krawec provided information in his direct testimony regarding the turbine replacement. He stated that the turbine replacement will take place during Unit 1's refueling outage and will be placed into service by October 2011. He said the turbine replacement is reflected in rate base at zero net plant value cost for purposes of earning "return on" this plant. He noted that I&M will update its rate base and depreciation prior to the evidentiary hearing if the final net costs of replacement differs from the estimate.

(b) OUCC Case-in-Chief. Mr. Dunkel noted that I&M's depreciation study "excludes $21,610,932 insurance proceeds received for Ul Turbine Repair" but that I&M did not exclude the retirements, cost of removal and other costs caused by the Cook Unit 1 fire. He stated that I&M intended to exclude costs caused by the Cook Unit 1 turbine fire, which occurred in 2008, and that the gross removal related to the Ul Turbine Repair was not excluded from the net salvage analysis used in the depreciation study. In addition, the retirements related to the Ul Turbine Repair were not removed from either the net salvage analysis or the interim retirement ratio calculations used in the I&M depreciation study.

Mr. Dunkel stated that the impact of these exclusions has two effects on the depreciation rates. By excluding the gross salvage, I&M increased the depreciation rates; by not excluding the cost of removal caused by the turbine fire, I&M did not make the adjustment that would lower the depreciation rates. Mr. Dunkel therefore concluded that the adjustment I&M made for the Cook Unit 1 turbine fire was not a balanced adjustment. He recommended that in addition to excluding the gross salvage related to this turbine fire, the associated cost of removal and retirements should also be excluded from the depreciation analysis in order to be fair and balanced. The depreciation rates he recommended properly excluded the retirement, gross salvage, and cost of removal amounts related to the turbine fire in Cook Unit 1.

**Table 1:**

**Comparison of Current. Davis Proposed, and Dunkel Proposed Depreciation Rates**

| | | | Davis Recommended | | Dunkel Recommended | | |
|---|---|---|---|---|---|---|---|
| | 12/31/10 | Current | | Difference | | Difference | Difference |
| Functional Group | Investment | Rate % | Rate % | from Current | Rate % | from Current | from Davis |
| | (a) | (b) | (c) | (d)=(c)-(b) | (e) | (f)=(e)-(b) | (g)=(e)-(c) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Nuclear Production | 2,154,842,670 | 1.16% | 1.74% | 0.58% | 1.72% | 0.56% | -0.02% |

Mr. Dunkel concluded by recommending that the Commission apply his 1.72% depreciation rate to the Cook Unit 1.

(c) I&M Rebuttal. Mr. Krawec said that in November 2011, I&M began recording depreciation expense associated with the new turbine and stopped recording depreciation expense associated with the old turbine. He testified that I&M is pursuing a settlement with its insurance provider (Nuclear Electric Insurance Limited ("NEIL")) concerning the turbine replacement. He stated that the pending insurance claim could impact the amount booked to net plant-in service for this investment. He also said that while it is appropriate to include the turbine investment in rate base in this case, I&M is willing to include only the incremental depreciation associated with this new investment in rates now and is willing to consider deferral of the return on rate base from this investment from the time the new rates established in this case go into effect until I&M's next rate case. Under this proposal, Mr. Krawec said that the ultimate return that would be recognized for ratemaking purposes would be limited to the amount of the investment in the new turbine that is not covered by the final amount of the NEIL insurance claim. Mr. Krawec argued the full amount of the investment in the new turbine should be included in rate base in this proceeding. He said I&M would "true-up" the actual return in its next base rate case reflecting the final outcome of the NEIL insurance claim if I&M is not granted its requested inclusion of the turbine in rate base in this case.

Mr. Krawec argued that due to the new turbine as of April 30, 2012, I&M's depreciation expense has increased by $2,014,184 (Total Company) or $1,302,274 (IN Jurisdiction) annually, as shown in Supplemental Exhibit SMK-S1. He stated that because the depreciation expense on the turbine will not be impacted by the outcome of the NEIL insurance claim, it is appropriate to recognize the depreciation in the revenue requirement in this case. He referred to the depreciation adjustments in Exhibit A-R5, Depreciation and Amortization Adjustment No. R5, to remove depreciation expense associated with the previous turbine, and Depreciation and Amortization Adjustment No. R6, to add depreciation expense associated with the new turbine.

(d) Commission Discussion and Findings. The question of the depreciation expense associated with the Cook Unit 1 Turbine was a disputed matter. I&M's proposed depreciation did not provide a complete picture of the necessary puts and takes, and as the OUCC noted, this resulted in an unbalanced adjustment. The OUCC recommended that in addition to excluding the gross salvage related to this turbine fire, the associated cost of removal and retirements should also be excluded from the depreciation analysis. This properly aligns costs and value with the remaining value of Cook Unit 1, and we therefore adopt the OUCC's recommended adjustment to depreciation on Cook Unit 1 and apply a rate of 1.72%.

Applying that adjustment and in light of the pending insurance issues related to the NEIL insurance coverage, I&M has proposed to include in rates now only the depreciation expense associated with this new investment. I&M has chosen defer the return on rate base from this investment from the time the new rates established in this case go into effect until I&M's next rate case. We find both of these proposals are reasonable and should be approved. As proposed by Mr. Krawec, the ultimate return that will be recognized for ratemaking purposes will be limited to the amount of the investment in the new turbine that is not covered by the final outcome of the NEIL insurance claim.

(2) Discretionary Pension Payments.

(a) I&M Case-in-Chief. I&M's proposed rate base includes $61,691,885 (Indiana Jurisdictional) for prepaid pension expense as of March 31, 2011. Petitioner's Exhibit A-6, p. 1, Line 7; Petitioner's Exhibit A-3, p. 1. Petitioner did not provide any testimonial support for this treatment. I&M removed the balance applicable to non-utility operations, *i.e.* River Transportation Division costs, from the Total Company amount but did not otherwise adjust the end of test year level of pre-paid pension expense. Brubaker Direct, at 24, lines 21 – 22 through p.25, lines 1-2; Petitioner's Exhibit A-6, p. 3.

(b) OUCC Case-in-Chief. OUCC Witness Margaret A. Stull, Senior Utility Analyst for the OUCC, presented testimony opposing the inclusion of prepaid pension expenses in rate base, noting that I&M's voluntary pension contributions do not represent an investment in used and useful utility plant, adding the payments are not required to provide quality, reliable utility service to Indiana ratepayers. Stull, at 5. Ms. Stull stated that if the Commission determines I&M should receive some benefit from its voluntary pension contributions, it should only receive a "debt return" as a revenue requirement based on the actual cost of debt incurred to fund the prepayments. *Id.* at 5-6. Based on Ms. Stull's recommendation, Mr. Eckert removed $91,758,368 of prepaid pension expense from rate base on a total company basis and $61,691,738 on an Indiana jurisdictional basis. Eckert Direct, at 39.

Ms. Stull explained that prepaid pension expense refers to certain voluntary pension contributions Petitioner elected to make in addition to the annual pension contributions required by the Employee Retirement Income Security Act ("ERISA"). She noted the prepaid pension expense payments that Petitioner desires to include in rate base were substantially made in 2005 and 2010. Ms. Stull noted that according to her investigation, the voluntary pension contributions I&M proposes to include in rate base were actually made by its parent company, American Electric Power Company, Inc. ("AEP"). She added that I&M employees participate in AEP's pension plan since there is no stand-alone I&M pension plan. However, since these are AEP payments, the financing for these payments is not included in I&M's capital structure. (See Petitioner's Exhibit A-7.) Ms. Stull noted these facts were recently examined in a Virginia Appalachian Power Co. rate case. According to the final order in that case, AEP funded these pension contributions through short-term commercial paper debt, which carries a much lower interest rate than the capital included in Petitioner's proposed capital structure[2]. Stull, at 6. (Attachment MAS-2).

Ms. Stull noted Petitioner's proposal, with respect to inclusion of prepaid pension expense in rate base, consists merely of an entry in its rate base schedule. In particular, Ms. Stull stated that beyond one line in Petitioner's rate base exhibit (Petitioner's Exhibit A-S6 – Rate Base: Per Books and Adjusted, page 1 of 13, line 7) showing "165 Prepaid Pension Expense" of $91,758,368 (Total Company) and $61,691,738 (Indiana), Petitioner provided in its case-in-chief

[2] Petitioner's Exhibit A-7 reflects an average long-term debt rate of 6.33% and an overall weighted cost of capital of 7.38%. Per AEP's 2011 annual report, the average short term commercial paper rate was .4%.

no explanation of its proposal regarding "prepaid pension expenses." Ms. Stull noted that consequently, Petitioner's case-in-chief does not indicate the date any prepayments were made, the entity that made the prepayments, the reason for any prepayments, the source of funds for any prepayments, the cost of the funds used, or the anticipated effect of the prepayments on ratepayers. Ms. Stull added that Petitioner did not explain why it seeks rate base treatment for the prepayments of pension expense or state the rationale that supports its proposed inclusion of these prepaid expenses in rate base. Finally, Ms. Stull observed Petitioner's case-in-chief or workpapers provided no documentation of the prepayments or the calculation of the amount included in rate base. Stull, at 5.

Through Petitioner's response to discovery questions, Ms. Stull ascertained the dates and amounts of each years' pension contributions along with Petitioner's calculation of the prepaid pension expenses proposed to be included in rate base (Attachment MAS-3,4, and 5). Through her review, she also learned that Petitioner did not make any contributions to its pension fund from 1993 through 2002 despite collecting funds for pension expense from rate payers as part of I&M's revenue requirement during this same period. Ms. Stull also provided a table, which showed no payments made in the years 2006, 2007, 2008, and 2009, despite the inclusion of funds in base rates for pension expense.

Ms. Stull explained why the use of low cost commercial paper debt to fund these additional pension contributions is significant. According to the final order in the Virginia Appalachian Power Company rate case, AEP executive management made its most recent 2010 pension pre-funding contribution based on the premise that the pre-funding would produce net cost savings because the pre-funding was being financed with low cost commercial paper. Stull, at 7.

Ms. Stull asserted that including this proposed "asset" in rate base would require customers to pay a much higher interest rate (i.e., I&M's full cost of capital) than the much lower interest rate actually incurred by AEP to borrow the funds. Therefore, it is not part of I&M's capital structure and is not reflected in I&M's weighted average cost of capital. Accordingly, Ms. Stull noted, ratepayers do not receive any off-setting benefit from a lower overall cost of capital by including this lower debt.

Ms. Stull explained why Petitioner should not be permitted rate base treatment of these discretionary pension contributions. She noted Petitioner is allowed to earn a return on its investments in utility plant to insure safe, reliable utility service for Indiana ratepayers. She asserted that Petitioner should not be allowed to borrow funds at a low commercial paper rate, invest this cash into its pension fund, earn a full return on these additional pension contributions from its ratepayers, and then pocket the difference for its shareholders. She noted that Indiana ratepayers properly pay a fair return on Petitioner's investment in utility infrastructure, but they should not be required to pay higher rates to fund discretionary payments to a pension fund, especially when those payments are funded through debt instruments with a low rate of interest. Stull, at 8.

(c) SDI Case-in-Chief. SDI Witness Ralph Smith also opposed I&M's proposed inclusion of prepaid pension expense as an asset in rate base. Mr. Smith asserted that because I&M's 2011 FERC Form 1 shows that its pension benefit obligation is currently underfunded, and has been since 2010, I&M has a long-term pension liability and that fact contradicts the Company's proposal to include in rate base the pension asset that resulted from voluntary management decisions. Claiming a pension asset in rate base when the Company's FERC Form 1 clearly shows that the defined benefit plan is underfunded and therefore a long-term liability is inappropriate. Smith, at 7-8. Mr. Smith testified that worker mobility, the Employee Retirement Income Security Act ("ERISA") and other compliance and reporting requirements has led to a discernible trend away from defined benefit plans. Mr. Smith noted there is evidence indicating this exodus away from defined benefit plans including a March 30, 2009 report from the U.S. Government Accountability Office (GAO-09-291).

Mr. Smith also provided the following illustrative examples of utilities that have closed, frozen, significantly modified or discontinued their defined benefit pension plans: PacifiCorp / Rocky Mountain Power, American Water Works Company, Inc., Aqua America, Inc., Verizon, Shenandoah Telecommunications Company, Cincinnati Bell, United Illuminating Company, Vermont Electric Cooperative (union employees), Connecticut Natural Gas, Southern Connecticut Gas, and Northeast Utilities. As a result of these factors, including I&M's proposed pension asset in rate base, could provide a disincentive for making reasonable reforms to the Company's pension plans that would reduce costs. *Id.* at 8-12.

Mr. Smith stated that pension funding levels are the result of discretionary AEP management decisions. He explained these decisions were anticipated to produce net savings based on AEP top management's assumption that the additional pension funding contributions would be financed using low-cost short term debt. However, including the discretionary funding contributions in rate base is inconsistent with the economic analysis upon which the AEP board relied for approving the additional discretionary funding, and results in an unwarranted burden on ratepayers if included in rate base. Frequently, there is a wide range between the minimum funding required under ERISA and the maximum annual funding, the range typically limited by the maximum tax-deductible funding contribution limitations placed by the IRS. Increasing funding of a defined pension plan (pension trust contributions) would earn a return, which would then reduce future pension expense. *Id.* at 7 and 12. Mr. Smith explained that making additional discretionary funding payments into the pension trust in amounts beyond ERISA requirements could potentially benefit employees and shareholders and result in additional costs to ratepayers. Additional factors putting pressure on pension plan costs include the poor investment market performance and low interest rates. I&M only has one funded pension plan to which trust fund earnings information applies, and in 2008, reported a loss of 23.9 percent. However, for years 2007 and 2009-2011, I&M experienced a gain. As explained in the Company's 2011 FERC Form 1:

> The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

*Id.* at 12-13

Mr. Smith contended pension expense associated with defined benefit pension plans should only be reflected in rate base as part of cash working capital base on a properly prepared lead-lag study, which has not been presented in this case. He considered Petitioner's request to single out pension expense as a separate balance from other balance sheet accounts to be included in rate base is unbalanced. *Id.* at 13. In a recent rate case involving Appalachian Power Company ("APCo") in Virginia, Case No. PUE-2011-00037, Mr. Smith noted that statements in AEP's board minutes revealed that recent decisions by AEP management to provide for prefunding of future pension obligations in 2010 was to be financed by AEP with a relatively low cost source of capital. It was concluded that the pension asset presented in APCo's rate case should not receive a return at APCo's overall cost of capital. In that Virginia rate case, APCo had included a lead-lag study to allow determination for the allowance of cash working capital, and pension expense was included in the expenses that were addressed in the lead-lag study. A provision was included for cash working capital related to the net payment lag for labor costs, including pension and other employee benefits. In that case Mr. Smith recommended, in addition to removing the prepaid pension from rate base, making a corresponding adjustment to provide interest on the average prepaid pension balance, net of related Accumulated Deferred Income Taxes ("ADIT"), at the commercial paper interest rate. Allowing financing costs on the net prepaid pension asset at the commercial paper rate addressed a source of financing for the prepaid pension asset by including the interest expense related to applying the debt-based financing above-the-line as an operating expense for ratemaking purposes. The additional offsetting adjustment would address concerns about the relationship between pension expense in rate base and operating expenses, and protect ratepayers from having their base rates for APCo's electric service increased unnecessarily as a result of the AEP management decision to pre-fund future pension obligations. Similar regulatory treatment of applying a debt-based return on pension asset amounts has also been applied by the Illinois Commerce Commission in a series of rate cases involving Commonwealth Edison Company ("ComEd"). ADIT directly related to I&M's pension asset that is removed from rate base should also be removed from the Company's capital structure. *Id.* at 13-15.

In 2011, I&M paid an average monthly interest rate of 0.407% on commercial paper, while AEP paid a weighted average interest rate of 0.51%. In comparison, the Company is requesting a pre-tax cost of capital of approximately 10.48%, which is 23.7 times higher than the 2011 commercial paper interest rate of 0.41%. Allowing the pension asset to be included in rate base would cost ratepayers $6.565 million. *Id.* at 15-16. The differential in financing costs and the pre-tax rate of return that the Company is requesting ratepayers pay on the pension asset included in rate base exceeds commercial paper financing by more than a factor of 7. Mr. Smith presented information on short term financing costs provided by the Company, as well as additional information on AEP commercial paper interest rates from AEP's SEC Form 10-K annual reports. He also presented evidence of information on the pre-tax rate of return that is applied to rate base. The discretionary decisions by AEP executive management to make additional contributions to the pension plan, which has led to the pension asset, result in increasing the revenue requirement because the financing cost to ratepayers exceeds the pension savings, and are contrary to the rationale for the discretionary funding that was presented to the AEP board. Charging ratepayers for a rate base return on this at I&M's requested pre-tax cost of capital disadvantages ratepayers more than it benefits ratepayers from the pension trust earnings on the additional funding beyond the minimum required funding that was made at the discretion of AEP top management. This type of funding seeks to benefit the employees by increasing the certainty of the availability of funds to pay pensions, and shareholders by creating a higher return from the inclusion of a prepaid asset in rate base. *Id.* at 17-18.

Mr. Smith stated that, to balance the interests of both the ratepayers and the Company's shareholders, the pension asset should be removed from rate base. Mr. Smith stated that if the prepaid pension asset is to be included in the revenue requirement it should be based on a debt rate, preferably the rate for commercial paper. *Id.* at19.

(d) I&M Rebuttal. In Petitioner's rebuttal case, Petitioner Witness Hugh E. McCoy discussed the testimonies of the OUCC's Ms. Stull and SDI's witness, Mr. Smith. Mr. McCoy claimed Ms. Stull's statement that Petitioner's proposal to include prepaid pension expense in rate base merely consisted of an entry in Petitioner's rate base schedule and was not supported by any testimony. Mr. McCoy claimed the prepaid pension asset is not a new item but has been reflected on the Company's books since 2005 in accordance with the governing accounting standard. McCoy Rebuttal, at 4-6. Mr. McCoy discussed the history and purpose of the prepaid pension asset as well as the associated accounting and Employee Retirement Income Security Act of 1974 ("ERISA") standards. McCoy Rebuttal, at 4-13.

Mr. McCoy said the prepaid pension asset is defined as the cumulative amount of cash contributions to the pension trust fund beyond the cumulative amount of pension cost included in the cost of service used for ratemaking purposes. *Id.* at 6. He said the prepaid pension asset is recorded on the Company's books in accordance with generally accepted accounting principles under FASB ASC 715 (formerly FAS 87) which determines the amount of pension cost on the income statement and in cost of service. He said the additional pension contributions were not absolutely required as ERISA minimum required contributions at the times they were made. But he claimed if the additional contributions had not yet been made, ERISA would have required the Company to make the contributions. He alleged the Company began making contributions before they were absolutely required in order to even out such required contributions over several years and to minimize the total required contributions during this period because investment income on early contributions reduces the total funding requirement. *Id.* at 13-14. Mr. McCoy claimed customers have benefitted because these additional contributions resulted in additional investment income in the pension trust and this in turn reduced pension cost that is recognized for ratemaking purposes. *Id.* at 14.

I&M Witness Renee V. Hawkins, AEPSC Assistant Treasurer and Managing Director, Corporate Finance claimed that when the additional contributions were initiated, the Company was looking at mandatory pension contributions through the decade and chose to manage them with some discretion on the timing of the contributions. Hawkins Rebuttal, at 4. Ms. Hawkins suggested why the pension fund contributions were made prior to the mandatory contribution date. She claimed one reason was to manage the timing in order to fund when the cash is available instead of delaying until the contributions were mandatory under ERISA rules, at which point the company would have had no discretion on the timing of the funding. She suggested the contributions are necessary to meet the pension obligations.

Mr. McCoy disagreed that the contributions should not be included in rate base. He said rate base typically includes other property, such as working capital, fuel inventory, materials and supplies, and prepayments. McCoy Rebuttal, at 8. Mr. McCoy alleged the inclusion of the prepayment in rate base is consistent with well-accepted ratemaking principles and necessary both to compensate the utility for use of the funds it has advanced and to avoid a disincentive to the utility for making similar prudent advances in the future. He claimed such treatment is particularly warranted where the prepayment lowered both the current and future cost of providing service and thus benefited customers and the utility's ongoing ability to provide reliable service. Mr. McCoy claimed regulatory policy should encourage proper and efficient utility management and encourage decisions that are consistent with a commitment to maintaining the well-being and security of the work force and reducing the overall cost of service. He claimed if the Company were denied an opportunity to recover its cost of capital on the prepayment, then he asserted the Commission would seem to be sending a signal that a utility should do the bare minimum and consider only short-term effects, even if the result is not least cost for customers. *Id.* at 10.

Mr. McCoy said as a result of additional pension contributions made after March 31, 2011, the pension plan was approximately 86% funded as of December 31, 2011. *Id.* at 12. He said the additional pension contributions to the trust fund result in additional trust fund investment income that reduces annual FAS 87 pension cost. He showed that the prepaid pension asset reduce 2011 pension cost by approximately $7.1 million versus the actual 2011 pension cost. McCoy Rebuttal, at 7, 12. He claimed that without the savings produced by the additional pension contributions, the 2011 pension cost would have been much greater than the amount reflected in the revenue requirement. He suggested that if the Commission were to exclude the prepaid pension asset from rate base, the related $7.1 million pension cost savings also should be removed from cost of service. *Id.* at 13.

Mr. McCoy discussed Ms. Stull's testimony that the Company did not appropriately fund the pension trust from 1993 through 2002. McCoy Rebuttal, at 14-15. He said the final order in Cause No. 39314 was issued on November 12, 1993, so only a small portion of the year 1993 would apply to any analysis of historical ratemaking versus funding. *Id.* at 14. He claimed the Commission's acceptance of a particular cost for purposes of determining the utility's revenue requirement for ratemaking purposes (which is then used to establish just and reasonable rates for service), does not freeze, or mandate, continuation of the particular expense. *Id.* at 14-15.

Mr. McCoy said pension cost is determined under FAS 87 for ratemaking purposes. He said pension contributions are subject to ERISA and IRS requirements. He claimed it is unreasonable to expect the amount of pension cost and the amount of pension contributions to be equal. *Id.* Mr. McCoy said FAS 87 handles the difference between pension cost on an accrual basis and pension contributions on a cash basis. *Id.* at 16. Mr. McCoy claimed the FAS 87 prepaid pension asset already keeps track of the cumulative difference between pension cash contributions and pension cost, and periods of no pension contribution are already properly accounted for. *Id.*

Mr. McCoy agreed with Ms. Stull, and admitted it is true the Company made no pension contributions during the 1993 through 2002 period. He said total qualified pension plan cost for the period was slightly negative for this period. Mr. McCoy claimed if the Company had made pension contributions from 1993 through 2002, all other things being equal, the prepaid pension asset would be that much larger. *Id.* at 17.

Mr. McCoy said I&M financed its own pension contributions for its own employees and retirees through cash payments that are reflected in I&M's capital structure. *Id.* at 17. He claimed I&M's 2010 pension contribution was funded not with short-term debt but instead with available cash and that neither the 2010 contribution nor the 2005 contribution were funded with commercial paper on an ongoing basis. *Id.* at 18. He claimed the pension cost savings realized from the 2010 contribution were mainly due to reduced pension cost in subsequent years as a result of additional investment income on the 2010 trust fund contribution. Mr. McCoy alleged this pension cost savings and reducing the pension funding shortfall were the real reasons for making the 2010 contribution.

Mr. McCoy discussed Mr. Smith's claim that the Company has not demonstrated it has a prepaid pension asset and instead has a net liability. Mr. McCoy erroneously alleged Mr. Smith has "confused" two separate items that should be treated differently for ratemaking purposes: (1) the prepaid pension asset, and (2) the net funded position. *Id.* at 19. Mr. McCoy suggested Mr. Smith's "confusion" of the prepaid pension asset with the net funded position appears to be based on the circumstances in a recent NIPSCO case. Mr. McCoy claimed NIPSCO's prepaid pension asset, which was not included in rate base in the Commission's August 25, 2010 final order in Cause No. 43526, was not based on actual cash contributions to the pension fund but instead was allegedly based on the net funded position. In contrast, Mr. McCoy claimed I&M's prepaid pension asset represents the cumulative amount of actual cash pension contributions beyond the cumulative amount of pension cost included in cost of service. *Id.* at 22.

Mr. McCoy discussed Mr. Smith's testimony that funding is discretionary and the inclusion of the prepaid pension asset in rate base could provide a disincentive for making reasonable reforms to the Company's pension plan. McCoy Rebuttal, at 22. He claimed a prudent cash investment should not be excluded from rate base just because it was made before it was absolutely required. Mr. McCoy said that since January 1, 2011, all Company employees have been earning their pension benefits only under the cash benefit formula to which Mr. Smith suggests the Company should switch. *Id.* at 24.

Mr. McCoy discussed Mr. Smith's recommendation that the Company eliminate or severely restrict its defined pension benefit plan. He suggested the Company's pension plan is a significant component of total employee compensation. Mr. McCoy claimed Mr. Smith's recommendation to eliminate the prepaid pension asset from rate base would increase unpredictability and would restrict management's ability to prudently manage its pension plan in the best interest of customers. *Id.* at 25.

Mr. McCoy discussed Mr. Smith's recommendation that a lead-lag study is needed for pension cost. He claimed the cumulative amount of additional pension cash contributions beyond the amount of pension cost included in cost of service is already measured under FAS 87 by the prepaid pension asset. *Id.* at 26. He suggested the prepaid pension asset is enough for this additional cash investment to be included in rate base without the need for a lead-lag study of lesser items. *Id.*

Mr. McCoy discussed Mr. Smith's recommendation that financing costs of the pension contributions should be included at a debt rate based on low-cost commercial paper as an alternative to including the prepaid pension asset in rate base. McCoy Rebuttal, at 26-27. He claimed I&M's 2010 pension contribution was funded not with short-term debt but instead with available cash and neither the 2010 contribution nor the 2005 contribution were funded with commercial paper on an ongoing basis. *Id.* at 27. Ms. Hawkins claimed cash flow from deferred income taxes were used to fund I&M's pension contribution. Hawkins Rebuttal, at 5-6. Ms. Hawkins said if the Commission were to use a debt rate on the pre-paid pension as recommended by Ms. Stull and Mr. Smith, then the debt included in the cost of capital should be reduced, resulting in a cost of capital of 7.41% as shown on Petitioner's Exhibit RVH-R2.

(e) Commission Discussion and Findings. Petitioner made a commitment to its employees to fund its pension liability. Although Petitioner and its parent company, which participate in the same defined benefit pension plan, each have net pension liabilities, Petitioner proposes we include discretionary pension payments in rate base alongside used and useful utility plant investment.

The Employee Retirement Income Security Act ("ERISA") establishes the minimum amount of payments that Petitioner must make, and IRS rules with respect to tax deductibility establish the maximum amount of deductable payments that may be made. While Petitioner has not fully funded its current pension obligation, primarily in 2005 and 2010 Petitioner voluntarily made payments in excess of the minimum established by ERISA. Petitioner has included in its proposed rate base value the amount of payments made in excess of the ERISA established minimum. In essence, Petitioner asks this Commission to allow it to treat as rate base, as that term is used in IC 8-1-2-6, the value of these extra payments as if they were an investment in plant used to provide utility service to its customers. Based on Petitioner's proposed rate base value, Petitioner would earn a return on these discretionary pension payments. The OUCC and SDI specifically oppose the inclusion of prepaid pension expenses in rate base. The OUCC stated that I&M's voluntary pension contributions do not represent an investment in used and useful utility plant. The OUCC added that such payments are not required to provide quality, reliable utility service to Indiana ratepayers. Accordingly, the OUCC removed $91,758,368 of prepaid pension expense on a total company basis and $61,691,738 on an Indiana jurisdictional basis from rate base. Eckert Direct, at 39.

In its proposed order, Petitioner stated I&M's rate base properly includes such things as Materials & Supplies and Fuel Stock. Petitioner argued that including the prepaid pension asset in rate base is consistent with the long established practice of including similar utility investments in rate base. We draw a distinction between investments of cash needed to operate the utility's assets and this proposed asset. Including in rate base monies used for Materials and Supplies and Fuel Stock is a long established practice. They should not be used as a foot in the door to expand the definition of rate base beyond the definition long and well established by state law in IC 8-1-2-6.

The comparison of Petitioner's so-called prepaid pension expense with such accepted rate base items as Materials & Supplies or Working Capital is not suitable for this inquiry. What constitutes a purchase of materials or supplies, for instance does not require interpretation. Funds are used to purchase materials and supplies or they are not. Under Petitioner's proposal payments made to the pension fund may be operating expenses or they may be investments in rate base. This depends on what is considered to be a minimum payment by ERISA and how the Financial Accounting Standards Board considers it should be booked. We are reluctant to agree to a methodology for assigning payments to rate base that depends on what ERISA considers a minimum payment and how the Financial Accounting Standards Board considers pension payments in whole or in part should be booked. How a payment should be booked according to FASB does not establish how a payment should be treated for ratemaking purposes. That treatment is a function of careful and deliberate approval of practices over time. The argument advocating such treatment came after Petitioner's case-in-chief. As the OUCC's Ms. Stull noted, Petitioner embedded this treatment in its proposed rate base amount with no explanation except for a line item in Petitioner's Exhibit A-6. Petitioner has not provided the parties to this cause a sufficient opportunity to fully explore the issue. Nor has it provided this Commission a sufficient basis to expand the definition of rate base beyond its current state. A utility presenting a proposal of this scope has the burden of proof and must present evidence as part of its case-in-chief.

We also disagree with Petitioner's argument that not approving its request to include pension payments in rate base "would increase unpredictability and volatility of pension costs and would restrict utility management's ability to prudently manage its pension costs." While we agree that management should have the ability to prudently manage its pension costs, we do not consider that ability impaired by our decision to not allow Petitioner to treat its pension payments as an investment in plant. Pension payments to address a utility's current liability are not an investment in plant used or useful for the provision of utility service. As a result of Petitioner's discretionary pension payments, Petitioner's customers are not going to experience improved quality or reliability of their electric service.

In its proposed order, Petitioner also argued that the prepayment preserves the integrity of the pension fund, making the Company's employees and retirees "more secure because they know their pensions are being provided for." Petitioner asserted this enhances the retention of competent employees to ensure the provision of adequate and safe service. We would note that a significant portion of the pension prepayments was made in 2010 when Petitioner was making a concerted effort to solicit voluntary resignations through its workforce reduction efforts. It seems unlikely that Petitioner was motivated by a desire to retain employees when it made its pension pre-payments at that time. In any case, any decision by Petitioner or its parent to make its employees more secure does not justify the unprecedented ratemaking treatment Petitioner proposes of allowing discretionary pension payments to be defined as rate base. Such treatment is contrary to IC 8-1-2-6, which establishes what may and what may not be counted as property on which a utility may earn a return.

Petitioner proposes we include a pension asset in rate base even though Petitioner and its parent company, which participate in the same defined benefit pension plan, each have net pension liabilities. This is evidenced by I&M's FERC Form 1 for 2011, which shows the funded status of the defined benefit pension plans. This is at odds with the Company's proposal to include a pension asset amount in rate base.

Petitioner also claims that the discretionary pension payments have reduced the pension cost reflected in the revenue requirement in this Cause and may be expected to continue to reduce pension costs. However, Petitioner's claims that pre-2010 pension contributions have reduced expense are without any consideration of recent actual investment market losses to which the pension trust assets were subjected. Considering the substantial investment market declines in recent years, we may reasonably conclude that the discretionary pension funding contributions were subject to the same market losses as other investments, and thus are part of the overall market losses that must subsequently be made up in the form of higher current and future pension expense. Petitioner's proposed ratemaking treatment not only would create a new kind of rate base on which its ratepayers would pay a return, but it would require customers to pay a higher price for past market losses and bear greater risk in the future.

We must also consider the unintended consequences of Petitioner's proposed treatment. If Petitioner's proposal to treat discretionary payments as a rate base asset is approved, it would logically require us to take a converse action under other circumstances. Petitioner claims to have acquired an asset through its discretionary payments. When a utility's total contributions to a pension plan are less than its total pension expense as established by FAS 87, then consistency and fairness would suggest that a liability exists that should be considered for ratemaking purposes as reduction to rate base or at least a source of zero-cost capital. In the past when Petitioner had such a liability, it did not ask us to consider reducing its rate base by that liability. Petitioner has made no such request, nor has any utility, or any party. Petitioner's request is unwarranted and unwise. We decline to grant it. We also note there is a very real question as to whether Petitioner can be considered to have an asset at the same time it retains a liability as indicated by SDI witness, Mr. Smith.

In its proposed order, Petitioner asserts that through the pension payments in excess of the minimum required by ERISA, the customer is getting the use and benefit of the utility's funds. Petitioner asserts customers should "pay" for the use of the utility's funds at the utility's authorized cost of capital. We note that from 1993 through 2002 Petitioner made no pension payments though it had been provided pension expense as part of its revenue requirement for the rates that covered that period. Petitioner insists that its ratepayers pay for the "use" of money Petitioner used to fund its pension obligation through the discretionary payments it made. Presumably, Petitioner had the "use" of the pension expense monies that had been included in its revenue requirement from 1993 through 2002. No party has suggested Petitioner reimburse the ratepayers for the "use" of that money.

Petitioner asserted that the benefit from use of the money came in the form of a lower revenue requirement for pension expense. Any assertion with respect to savings achieved was not part of Petitioner's case-in-chief. As such, we do not consider any amount of savings alleged to be adequately evaluated since this assertion was made for the first time in Petitioner's rebuttal case. No party has had an opportunity to submit testimony challenging such assertion made for the first time in Petitioner's rebuttal case. We have insufficient evidence before us to make such a determination. In either case, the level of savings achieved is both academic and irrelevant to our inquiry. Other actions could also have reduced the pension expense to Petitioner's ratepayers including trust investments that yielded a higher return. Petitioner could have made payments to its pension fund from 1993 through 2002. That would also have presumably reduced the level of pension expense to today's ratepayers. We decline to become embroiled in such inquiries to make rate base determinations. We are unwilling to buy into the legal fiction that discretionary payments made to fulfill Petitioner's current pension obligation is an investment in plant, particularly after Petitioner's failure to invest in its pension fund from 1993 through 2002.

Both the OUCC and SDI noted the Virginia Public Service Commission recently declined a request to treat the very same payments as rate base additions. See Appalachian Power Company ("APCo"), Case No. PUE-2011-00037. SDI witness Smith noted that statements in AEP's board minutes revealed that recent decisions by AEP management to provide for prefunding of future pension obligations in 2010 was to be financed by AEP with a relatively low cost source of capital. With that knowledge, the Virginia commission declined to provide the AEP affiliate with a return at the affiliate's weighted cost of capital as proposed here. Mr. Smith also noted that in 2011, I&M paid an average monthly interest rate of 0.407% on commercial paper, while AEP paid a weighted average interest rate of 0.51%. By comparison, Mr. Smith noted the Company is requesting a pre-tax cost of capital of approximately 10.48%, which is 23.7 times higher than the 2011 commercial paper interest rate of 0.41%. To afford Petitioner a full return on these discretionary payments does not represent an appropriate balancing of the interests of the ratepayers with those of the utility. Both the OUCC and SDI maintained there should be no favorable ratemaking treatment for such an expenditure. We agree. In the past, and in this cause, the Commission has allowed Petitioner to include pension expense as a revenue requirement. For ten years, Petitioner collected funds but made no payments. No party requested a debit from Petitioner's rate base value as a result. No party has requested a refund of those funds Petitioner collected as a revenue requirement in those years. We decline to impose as an additional revenue requirement a debt expense associated with Petitioner's pension payments.

Based on the foregoing, we hereby reject Petitioner's request to include discretionary pension payments in rate base. We approve the OUCC's adjustment to exclude from Petitioner's rate base the $61,691,885 (Indiana Jurisdictional) amount Petitioner has included in its rate base schedules.

(3) Materials & Supplies.

(a) I&M Case-in-Chief. I&M adjusted its proposed rate base to eliminate $3,828,761 of materials and supplies applicable to non-utility operations, *i.e.*, River Transportation Division. Brubaker Direct, at 25; Rate Base Adjustment No. 13. Otherwise, I&M's proposed revenue requirement used the end of test year materials and supplies ("M&S") amount of $186,556,239 (Total Company) or $121,493,195 (Indiana Jurisdictional). Petitioner's Exhibit A-6, p. 1, Line 10; Petitioner's Exhibit A-6, p. 4 (RB-13).

(b) OUCC Case-in-Chief. OUCC Witness Eckert did not oppose I&M's proposed rate base adjustment to eliminate the M&S applicable to non-utility operations, but disagreed with I&M's proposal to use the M&S amount as of March 31, 2011 as the pro forma test year amount. Eckert, at 38. Mr. Eckert testified that Petitioner's proposed Materials and Supplies amount to be included in rate base was not representative and not appropriate for inclusion in rate base. Instead, Mr. Eckert recommended that a 13 month average ($178,075,379) of materials and supplies ending March 31, 2011 be included in rate base. Mr. Eckert noted that Petitioner used the March 31, 2011 balance, which was the second highest balance Petitioner had incurred for the six year period from April 2006 through February 2012.

Mr. Eckert testified that prior to December 2010, the highest materials and supplies amount for a single month (December 2009) was $177,057,767. Mr. Eckert noted that looking at the period from April 2006 through February 2012, the months he used for his 13-month average includes the four highest months of the six year period – the last four months of the test year, December 2010 through March 2011. *Id.* at 38.Using a 13 month average for the period March 2010 through March 2011, he recommended the M&S balance to be included in rate base should be $178,075,379 (Total Company). *Id.* at 39.

(c) I&M Rebuttal. I&M Witness Jeffrey L. Brubaker, AEPSC Director - Regulatory Accounting Services, argued that Mr. Eckert's proposal to use a 13-month average balance instead of the end-of-period balance in rate base is arbitrary. In Mr. Brubaker's view the 13-month average does not show that the end of period balance for the test year is unreasonable. Mr. Brubaker said there were certain errors in Mr. Eckert's calculation of his proposed M&S Indiana jurisdictional adjustment. *Id.* at 5. Mr. Brubaker argued that while OUCC Witness Eckert indicated that the test year included four of the highest months over a six year period, Mr. Eckert did not recognize that the test year also contains five of the seven lowest monthly M&S balances in the 25-month period December 2009 through December 2011, and five of the twelve lowest monthly balances in the 33-month period April 2009 through December 2011. Based on this assertion, Mr. Brubaker concluded that Mr. Eckert's 13-month average balance results in an unreasonably low balance of M&S to be included in rate base. *Id.* Mr. Brubaker proposed that if the Commission does use a 13-month average balance, the appropriate period would be from December 2010 through December 2011 as this period would correspond with the rate base cut off date in this Cause. *Id.* at 4. Mr. Brubaker calculated the 13-month average balance of M&S in rate base for December 2010 through December 2011 to be $180,987,920, to produce a M&S Indiana jurisdictional adjustment of ($3,549,664). *Id.*; Petitioner's Exhibit JLB-R3. Nevertheless, Mr. Brubaker recommended the Commission reject Mr. Eckert's proposal to use a 13-month average and instead include the actual March 31, 2011 balance of M&S in rate base. *Id.* at 6.

(d) Commission Discussion and Findings. The value of Materials and Supplies that Petitioner proposed to insert into its rate base of $186.6 million is higher than any value in the nine months subsequent for which we have the data. In fact, it exceeds the average of those months by approximately $8 million. It also exceeds the 13-month average Petitioner recommends as an alternative by approximately $5 million dollars. When asked why his proposed value of $186.6 million should be considered representative of Petitioner's *pro forma* Materials and Supplies balance, Mr. Brubaker insisted that the balance at the end of the test year was required by the Commission's minimum standard filing requirements and that makes it representative.

We recognize no such requirement that the balance of Materials and Supplies at the end of the test year be used and deemed representative of the utility's pro forma needs. Rather, 170 IAC 1-5-12 (4) provides that an electing utility is required to provide in its work papers "the materials and supplies balances at the beginning of the first month and end of each month of the test year with the average of thirteen (13) monthly balances shown separately."

This language suggests that in determining the amount of materials and supplies that should be included in an electing utility's rate base, we not simply adopt the balance at the end of the test year as Mr. Brubaker asserts. Rather, this language suggests we consider a thirteen month average roughly corresponding to the test year as a whole. Yet Mr. Brubaker insisted during cross-examination that an end of test year balance is required by our minimum standard filing requirements. Thus, it seems that I&M's proposed Materials and Supplies balance is based on a faulty premise.

During cross-examination of Mr. Brubaker, the OUCC offered an exhibit that illustrates why a 13-month average is useful and favored to determine a utility's ongoing materials and supplies balance for rate base purposes. Certain values in ratemaking are appropriate to base on the end of test year or the end of the adjustment period. These may include plant values, customer count, and wages and benefits. These type of expenses or values are not prone to the month to month variations that the OUCC's cross-examination exhibit No. 53 illustrate are true with respect to Materials and Supplies.

In the 22 months shown on OUCC's cross-examination exhibit No. 53, the monthly values are shown to decline throughout the year through November followed by a significant increase in the value in December. For instance the value of materials and supplies in November 2010 was \$172.2 million followed by a value of \$187.5 million in December 2010. Similarly, the materials and supplies balance in November 2011 was \$172.1 million followed by a value of \$180.7 million in December 2011. These fluctuations in values indicate that an average is the most appropriate way of establishing Petitioner's pro forma revenue requirement. To rely on a value at the end of the test year or any other single month would promote last minute purchases of materials and supplies to augment rate base. These augmentations would not be representative of ongoing operations.

Other than his insistence that our rules require the use of a balance at the end of the test year, Mr. Brubaker provided no explanation why the end of test year balance should be considered representative of its ongoing operations. Indeed, we note that looking at the period from April 2006 through February 2012, the period that Mr. Eckert discussed in his testimony, the amount proposed by Petitioner is the second highest value during that nearly six year period. The eleven months following Petitioner's proposed Materials and Supplies balance (March 2011-\$186.6 million) are all significantly lower. The next highest value in the subsequent months through December 2011 is nearly \$4 million less (May 2011- \$182.8 million). We do not consider Petitioner's end of test year balance for materials and supplies to be representative of Petitioner's prospective operations. We find that Petitioner's Materials and Supplies rate base should be based on a 13-month average.

Mr. Eckert's 13-month average, which uses the test year months, appears to be the proposal that is most in keeping with 170 IAC 1-5-12. However, that is not the end of our inquiry on this issue. Subsection (4) of 170 IAC 1-5-12 further states that "if any of the balances are not representative of the utility's current operating plan, the utility shall include an explanation of the relevant circumstances." This suggests there may be a reason not to use a 13 month average based on the test year. Neither Petitioner nor Mr. Brubaker specifically asserted that Mr. Eckert's average is not representative of I&M's current operating plan. Nor did I&M or Mr. Brubaker provide any explanation that would permit that conclusion.

Nonetheless, Mr. Brubaker does find fault with Mr. Eckert's choice of months to use for the 13-month average he calculated. This criticism was made in part to support Mr. Brubaker's assertion that we should use the balance at the end of the test year. Had Mr. Brubaker not based his own proposed Materials and Supplies balance on a misunderstanding of what was required by our minimum standard filing requirements, it is possible that he would not have had reason to criticize Mr. Eckert's thirteen month average. As it was, Mr. Brubaker considered his thirteen month average, which uses the months from December 2010 through December 2011, to be superior to Mr. Eckert's. Therefore, we will address Mr. Brubaker's criticism of Mr. Eckert's choice of months by way of comparison with Mr. Brubaker's choice of months for his 13-month average.

Mr. Brubaker noted that, while Mr. Eckert's 13-month average included the four highest monthly amounts since April 2006, the test year also contains five of the seven lowest monthly M&S balances in the 25-month period December 2009 through December 2011, and five of the twelve lowest monthly balances in the 33-month period April 2009 through December 2011. Based on that, Mr. Brubaker asserted that Mr. Eckert's 13-month average balance of M&S results in an unreasonably low balance of M&S to be included in rate base.

Although we do not dispute that Mr. Eckert's 13-month average relies on five of the 12 lowest months between April 2009 and December 2011, the inclusion of those months do not make Mr. Eckert's 13-month average unrepresentative of I&M's future operations. Indeed, it is the nature of an average to use lower values with higher values. If the inclusion of high or low values was a basis to dispute the OUCC's 13-month average, then we would have a more compelling reason to disregard Petitioner's 13-month average. During cross examination of Mr. Brubaker by the OUCC, Mr. Brubaker acknowledged that his proposed test year included *ten* of the highest balances in the 33 months he asked us to consider in his rebuttal testimony.

Although Petitioner's 13-month average includes more recent values than the OUCC's, we do not consider inclusion of the more recent values to make Petitioner's 13-month average superior. Indeed, Petitioner's 13 months include two Decembers, the month that Petitioner significantly increases its amount of Materials and Supplies. A 13-month average that includes two Decembers would tend to overstate I&M's typical operations. (We also note that the Materials and Supplies balance in November 2011 and November 2010 are among the very lowest values for which we have data in this Cause. We would consider a 13-month average that duplicates such low values to also be suspect.) Petitioner has not shown that we should abandon a 13-month average that was calculated in accordance with our rules at 170 IAC 1-5-12. We adopt the OUCC's 13 month average, adjusted for the errors identified by Mr. Brubaker and acknowledged by Mr. Eckert on the stand.

Having determined to use the OUCC's 13-month average, we note the difference between Mr. Brubaker's preferred 13-month average and his proposed value based on the end of the test year balance are greater ($6 million) than the difference between Mr. Brubaker's 13-month average and Mr. Eckert's 13-month average (less than $3 million).

C. **Original Cost Rate Base.** Based upon the foregoing findings with respect to the proposed adjustments to rate base, the Commission finds that the net original cost rate base (Indiana Jurisdictional) for I&M is $2,324,528,204 and is calculated as follows:

| | |
|---|---|
| Net Plant At Original Cost | $2,185,361,368 |
| OPEB | $ 1,478,564 |
| 165 Prepaid Pension Expense | $ 0 |
| 253 Deferred Gain Rockport 2 Sale | $ (26, 201,384) |
| 151 Fuel Stock | $ 47,809,575 |
| 156 Other Materials & Supplies | $ 116,080,081 |
| Original Cost Rate Base | $2,324,528,204 |

**D. Fair Value.**

(1) I&M Case-in-Chief. Petitioner's Witnesses David. C. Moody, Vice President, Shaw Consultants International, Inc. and Michael E, Green, Senior Executive Consultant with Shaw Consultants presented testimony and exhibits concerning the valuation of I&M's plant and equipment.

Mr. Moody inspected Petitioner's transmission, distribution and general plant for this valuation. Moody Direct, at 2. His appraisal estimated the value of Petitioner's electric plant in service as of March 31, 2011, on the basis of the cost to construct the property new less existing depreciation ("Current Cost"). *Id.* at 3. He utilized methodologies for such property valuation, including the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman Index"), for application to the original costs by years of installation to obtain the Current Cost as of March 31, 2011. *Id.* at 5-7.

Mr. Moody explained how he estimated the depreciation allowances to be applied to Current Cost and noted that the allowances for depreciation constitute the differences between Current Cost and Current Cost less depreciation. *Id.* at 7-8. For the Rockport Plant and Petitioner's other Production Plant, Mr. Moody's opinion of the depreciated Current Cost is based on the results of the market value appraisal conducted by I&M Witness Green. *Id.* at 8-9.

Mr. Green, an Accredited Senior Appraiser in public utilities and Certified General Real Property Appraiser, estimated the appraised value of Petitioner's electric production plant as of March 31, 2011, on the basis of the income approach. Green Direct, at 3. Mr. Green compared the results of the income approach to available comparable sales data as a test of reasonableness. *Id.* The values indicated by the income approach were then used by Mr. Moody to measure accrued depreciation in the cost approach. *Id*

Mr. Green testified that an income approach valuation of an electric power generating plant is typically based on a DCF analysis. *Id.* at 4. He stated that the DCF analysis requires a market study to develop a long term forecast of plant performance, economic dispatch, market revenues and variable operating expenses, among other things. It also requires a projection of operation and maintenance ("O&M") expenses and capital expenditures necessary to support the level of projected future operations. He added that market revenues minus O&M expenses, capital expenditures and income taxes result in a forecast of future after tax cash flows which are then discounted back to present value at a market based after-tax weighted average cost of capital ("WACC"). *Id.*

Because there is not an active market for non-Production utility plant, Mr. Moody used indirect methods for determining depreciation for this plant. *Id.* at 9-10. Mr. Moody discussed his determination of depreciation for the Production Plant, Transmission Plant, Distribution Plant and General Plant and presented the overall results of his analysis. *Id.* 10-14. He concluded that the Current Cost of the electric plant in service at March 31, 2011 was $15,588,394,590 and the Current Cost less depreciation was $7,767,969,769. *Id.* at 14 (Revised).

To determine the "fair value" of the used and useful property, Mr. Moody proposed the Commission give weight to the net original cost of the property and to its net Current Cost. *Id.* at 15. Mr. Moody discussed how the relationships of provided capital affect his proposed calculation of fair value. *Id.* at 17. He stated that the two generally accepted indicators of fair value are the depreciated original cost and the cost to construct the electric properties new less existing depreciation. Mr. Moody stated that fair value is generally regarded as being a weighting of these two indicators. The balancing of how much of each is a judgment based on what is fair. *Id.*

Mr. Moody testified that original cost less depreciation is an account of actual historical investment reduced by annual accruals of depreciation. *Id.* He said because existing depreciation (as opposed to accounting depreciated) varies according to advances in design and construction, and according to the use of the assets, the methodology he proposed for the calculation of fair value reflects the characteristics of the indicators in the same proportion as the provided capital used to construct the assets. In other words, a certain percentage of Petitioner's capital structure is made up of fixed obligations (debt, preferred stock and no-cost capital) that are unaffected by inflation or the physical characteristics of the assets. *Id.* Mr. Moody proposed that the "fair value" should reflect this same proportion of original cost less depreciation since it has the same unvarying characteristics. Another percentage of the capital structure, that is, the remainder after all fixed obligations are satisfied, consists of equity capital. *Id.* He testified that the return on common equity is affected by yearly changes in inflation and by the physical operating condition of the assets, to the extent that the operating condition affects performance. *Id.* He said this portion of the fair value should be weighted with a pro rata share of the Current Cost to construct the electric properties in service less existing depreciation because this indicator reflects the impact of the same phenomena.

Mr. Moody estimated the fair value based on the capital structure provided by Ms. Hawkins and the original cost less depreciation found on Petitioner's books and records. He stated that the cost to construct the electric properties new less existing depreciation is taken from the results of his appraisal. The result of this analysis for plant in service as of March 31, 2011 is as follows:

| | Cost | Weight | Contribution |
|---|---|---|---|
| Original Cost Less Depreciation | $3,190,052,163 | 57.33% | $1,828,856,905 |
| Current Cost Less Depreciation | $7,767,969,769 | 42.67% | $3,314,592,700 |

| | |
|---|---|
| Fair Value<br>Net Electric Plant, Total Company<br>(Moody Direct, p. 19 (Revised)). | $5,143,449,605 |
| Net Electric Plant, Indiana Jurisdictional<br>(Petitioner's Exhibit TAC-3 (Revised) | $3,468,969,555 |

(2) OUCC Case-in-Chief. OUCC Witness Edward R. Kaufman, CRRA, Senior Analyst for the OUCC, raised several significant issues calling into question the reasonableness of Petitioner's estimated fair value rate base. Kaufman Direct, at 67. First he described the roles that six separate I&M witnesses (Chodak, Avera, Green, Moody, Caudill & Krawec) played in developing I&M's fair value increment proposal. Kaufman Direct at 60-61. Mr. Kaufman advised that I&M is seeking a fair value increment above what would be produced under original cost rate making (Chodak Direct, at 29-31). He pointed out I&M's proposed fair value rate base of $3,468,969,555 (Caudill Direct, Ex. TAC-3 revised) exceeded its proposed original cost rate base by $1,255,944,732 (Krawec Direct, Ex. SMK-1 revised). He described Dr. Avera calculating an incremental fair rate of return of 1.72%, then multiplying that amount by the $1,255,944,732 fair value incremental rate base, produces a return on fair value of $21,602,249. When grossed up for income taxes this figurer producing a "Fair Value Incremental Revenue Requirement" of $35,978,546, of which Petitioner seeks to include 50% ($17,989,273) in its proposed revenue requirements. *Id.* at 61.

Mr. Kaufman demonstrated that Petitioner's $18M fair value increment made up more than 10% of Petitioner's proposed $174,286,000 jurisdictional revenue deficiency. Mr. Kaufman also highlighted a specific request for Petitioner's witness Chodak: if other operating expenses are decreased, the Commission should consider giving greater weight in the revenue requirement to the return on fair value of the Company's utility property. *Id.*, citing Chodak Direct at 31:11-16.

Having reviewed the testimony and exhibits of Petitioner's witnesses Green and Moody, Mr. Kaufman determined both of their analyses included miscalculations that called into question the reasonableness of Petitioner's estimated fair value rate base. Kaufman Direct, at 67-71. Mr. Kaufman pointed out numerous assumptions (revenue, expense, capital expenditure, capacity factor, reserve margin and electricity price) in Mr. Green's analysis; changing any one these assumptions would affect cash flow and subsequently, the plant's estimated value. For each generating unit, Mr. Green estimated revenues, expenses and capital expenditures over the next twenty years (2011 – 2030), and for each year he calculates an after-tax free cash flow. Mr. Green then calculates a terminal value for the remaining life of the plant. Finally, Mr. Green discounts these values back to a net present value. These cash flows are described in Exhibit MEG-4.

Mr. Kaufman highlighted the dramatic increase in capacity prices (increasing from $33.23 $/kW-yr in 2014 to $153.18 $//kW- yr in 2020) in Mr. Green's analysis. The associated annual revenues for Cook Unit 2 over that period more than quadruple (from $35,793,000 in 2014 to $164,974,000 in 2020). Kaufman Direct, at 69. The approximate $129M capacity revenue increase is significant considering the 2020 total estimated after tax cash flow is $189,527,000.

Mr. Kaufman stressed the plants' retirement cost issue. He testified that upon their retirement, portions of I&M's generating plant will have negative salvage value, which in turn affects fair value. The Commission expressed similar concerns in their final order in Indiana – Michigan Power Company, Cause No. 39314, order dated November 12, 1993. At page 59 of the order the Commission stated as follows:

> The record in this Cause is replete with Petitioner's evidence supporting the position that upon retirement Petitioner contends, and has persuaded us, that such plants must be demolished upon retirement. We see nothing in the evidence indicating that Mr. Jerominski's reproduction cost new study has reflected these realities.

Mr. Kaufman recommended that the Commission should consider net demolition costs when determining Petitioner's fair value rate base. Kaufman Direct, at 69.

Regarding RCNLD studies, Mr. Kaufman noted the inconsistency between Petitioner's plant's original construction scope (over a series of decades) as opposed to one massive construction project. While RCNLD studies estimate costs assuming the plant would be reconstructed as it currently exists, reconstruction as a single project would improve both design and construction efficiencies. The original construction timing, differing management teams, & demand growth assumptions would all cause a newly reconstructed plant to differ from the original. Technical advances have occurred throughout I&M's existence, including - type of plant being constructed, equipment and construction personnel. Even if efficiently designed at the time of construction, Petitioner's plant could be redesigned and reconstructed today in a more efficient manner. Failing to account for the shortcomings or inefficiencies incorporated into an unadjusted RCNLD study, will overstate the fair value of the utility.

Mr. Kaufman also criticized Mr. Moody's RCNLD study for not adjusting the results recognizing improvements in productivity that have occurred over the life of the assets. Kaufman Direct, at 70-71. He testified that as it relates to physical assets, technological change requires a successively smaller dollar investment over time to produce a given volume of product or service output. Put differently, improvements in technology show up in improvements in the productivity of assets over time. Mr. Kaufman cited several IURC cases where the utility witness recommended accounting for improvements in productivity and recommended adjusting the results of an RCNLD study. All three cases relied on productivity indexes from the Bureau of Labor Statistics and recommended using a productivity indexes from 1.2% to 2.5%.

Mr. Kaufman also testified that if the Commission feels compelled to make fair value rate base finding that is other than original cost, he believed that Petitioner's Indiana Jurisdictional fair value rate base was no more than $2.9 billion.

(3) IG Case-in-Chief. [NOTE - OUCC IS NOT PROVIDING ITS OWN SUMMARY FOR THIS SECTION OF THE PROPOSED ORDER. OUCC

ADOPTS THE INDUSTRIAL GROUP'S SUMMARY OF WITNESS GORMAN'S FAIR VALUE TESTIMONY.]

(4) I&M Rebuttal. (NOTE - OUCC is not providing its own summary for this section of the proposed order regarding any criticism of IG witness Gorman. OUCC adopts the Industrial Group's summary of I&M's Fair Value rebuttal witness as it relates to witness Gorman's fair value testimony OUCC's proposed summary of I&M's rebuttal regarding criticism of OUCC witnesses follows.)

Mr. Green argued that Mr. Kaufman mixes concepts when he contends that the "estimated value is intended to be used as an input to determine Petitioner's authorized rates, but those same rates charged for electricity are used to determine the plant value." Green Rebuttal, at 6 quoting Kaufman Direct, at 68. Mr. Green testified that the revenues used to determine plant value are based on the competitive wholesale market for electricity. The wholesale market rates used to estimate plant value are projected over a long period of time into the future and vary considerably from one year to the next. He stated the production portion of Petitioner's retail electric rates is derived from a return on the fair value of Petitioner's property plus recovery of actual operating expenses which only varies as a consequence of rate proceedings. He said it would be utterly coincidental for projected market revenues in any given year to equal the Petitioner's production cost of service. *Id.*

Mr. Green also responded to Mr. Kaufman's concern that capacity prices in the DCF increase and capacity revenues at Cook Unit 2 are significant compared to the after tax cash flow. Green Rebuttal, at 6. He stated Mr. Kaufman points out that capacity prices show a dramatic increase over time; he did not provide any analysis of the PJM Reliability Pricing Model ("RPM") or the market fundamentals that drive RPM pricing. Mr. Green claimed the PJM website's description of the RPM reveals that it "includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants, but demand response and transmission facilities." *Id.* at 7. He said the fact that capacity market prices are projected to equal "net CONE" ("cost of new entry") at the time when reserve margins signal the need for new resources should come as no surprise, given the construct of the market and the intent of the RPM. *Id.*

Mr. Moody argued that the other parties' criticisms regarding the reliability of his reproduction cost new less depreciation valuations, including the conjecture that the analysis might not reflect the technological obsolescence of I&M's plant and equipment, are ill founded. First, by using a market-based approach to valuing the production plant, all losses in value for those assets are accounted for, including technological obsolescence. He argued that the retirement of Units 1, 2, and 3 at Tanners Creek is because the units are 60 years old or more, and the fact that they have simply reached the end of their economic useful lives. Moody Rebuttal, at 2. Second, Mr. Moody claims with respect to non-production plant, the majority of I&M's investment is in facilities for which there has been little or no technological improvement for many years. These facilities include poles, towers, conductors, services, conduit, and line transformers. These non-production accounts make up over 86 percent of the investment on a Current Cost basis. He said, of the balance, by far the largest portion (an additional 12 percent) is in transmission and distribution substation equipment. Mr. Moody testified that although there has been incremental technological improvement in some types of substation equipment over the years, these improvements have not led to either lower cost or shorter lives for existing equipment. He stated as a result, it would be inappropriate to make any broad adjustment to the Handy Whitman Index to attempt to adjust for technological improvement. He added that if he were to discover any equipment or classes of equipment that exhibited technological obsolescence, the appropriate approach would be to identify the exact nature of that obsolescence and to address it specifically.

Mr. Moody calculated the impact on the fair value analysis of Mr. Green's revisions to the DCF analyses and claimed that the revised analysis had an immaterial effect on the fair value analysis. Mr. Moody clarified that his opinion remains, that the fair value of I&M's property in service at March 31, 2011 is $5,143,499,605. He said the difference between his opinion and the result of using Mr. Green's revised analysis is 3.4 percent. Moody Rebuttal, at 4-5.

Mr. Moody agreed that the indicators that lead to fair value should not include "good will or presumptive values growing out of the operation of any utility as a going concern." Moody Rebuttal, at 5. Mr. Moody claimed there is no good will or going concern value included in any of the analysis. He said it is his understanding that the Commission has previously stated that "[w]e believe that the fair value of a utility's property is most analogous to the true current worth of the property, perhaps what a willing buyer would pay a willing seller in an arm's length transaction." Re Indiana Cities, Cause No. 39166 (IURC 7/8/1992), at 37; Re Indiana Michigan Power Co., Cause No. 39314 (IURC 11/12/1993), at 46. Mr. Moody claimed market value is only one of the various factors offered for consideration in arriving at fair value. He also presented a methodology to determine the "fair value" by weighting net original cost and net Current Cost. Moody Rebuttal, at 6.

Mr. Moody also responded to Mr. Kaufman's reference to "miscalculations" that call into question the reasonableness of Petitioner's estimated fair value rate base. Moody Rebuttal, at 6. He argued Mr. Kaufman discussed no errors in his calculation. Mr. Moody reiterated that the fair value he presented is not based only on net Current Cost, but reflects net original cost as well. Mr. Moody added the reasonableness of the fair value rate base is corroborated by looking at the results in comparison to alternative methodologies used by the Commission in the past. He said, one alternative, which does not rely on varying gas or electricity prices, changing technology, or plant production factors, is found in Re PSI Energy, Cause No. 42359 (IURC 5/18/2004). He said, the methodology used by the Commission in that case is to start with the most recently-allowed fair value rate base, make allowances for general inflation in the economy between the original fair value date and the date at issue, and to add net plant additions for the interim, producing an updated fair value. Mr. Moody showed that using this methodology, the fair value of the electric plant as of March 31, 2011 is $4,047,570,890. *Id.* at 7. He noted that using the methodology he proposed in this case, the fair value of I&M's plant allocated to retail service in Indiana in this case is $3,468,970,000 (rounded) as shown in revised Petitioner's Exhibit TAC-3 sponsored by Teresa A. Caudill, AEPSC Senior Regulatory Consultant - Regulated Pricing and Analysis. He stated that when this fair value amount is considered in light of the result using the alternative methodology presented above, the fair value he presented in this case appears to be not only reasonable, but conservative. *Id.* at 8.

Mr. Moody disagreed with Mr. Kaufman's contention that the fair value opinion is based on a hypothetical scenario that does not currently exist. Moody Rebuttal, at 8. He noted that the Commission has recognized that evidence of market value is important to the fair value process. See Re Indiana Michigan Power Co., Cause No. 39314 (IURC 11/12/1993) at 46 and 59; see also, Re Indiana Cities, Cause No. 39166 (IURC 7/8/1992). He stated that the value of the facilities is directly related to the value of the power they produce. He explained that it is unlikely that I&M would accept a price less than market value in a sale of the assets, or that the Commission would approve a sale at a below market price. He concluded the current use of the assets is irrelevant to the determination of market value. *Id.* at 9.

Mr. Moody also responded to Mr. Kaufman's testimony that retirement costs should be considered when determining fair value. Moody Rebuttal, at 9. Mr. Moody asserted that the cost of retirement of plant is not a rate base issue, but a depreciation recovery issue.

He said I&M's original cost (the other indicator for fair value in Mr. Moody's analysis) is net of depreciation and therefore does not contain an allowance for retirement costs. He said those costs are determined as part of the plant depreciation rate. Furthermore, the market value of the generating plants presented in this case was based on the actions of participants in the market for generating plants. He asserted that in that market, plants are not typically demolished. He said the site and much of the infrastructure is redeveloped as another, new plant site which has significant value. He testified this value offsets any cost of removal of the portions of the plant not used by the purchaser. *Id.*

Mr. Moody also responded to Mr. Kaufman's statement that if I&M's plant was reconstructed today it would be designed and constructed more efficiently and therefore would not be identical to the current system. Moody Rebuttal, at 9-10. He opined that this statement may or may not be true. He argued Mr. Kaufman assumes this to be the case but offers no evidence as to the degree of difference in design or cost that would be the result of constructing the system today. Mr. Moody added that the existing system was constructed in response to the needs of customers as determined at the time of construction. He said under the "regulatory pact," I&M is required to meet the needs of all of its customers, even if it is a detriment to the efficiency of the existing system. He stated that I&M is promised an opportunity to recover these costs that were made in the public interest. He argued that adjustments to the original cost contribution to fair value are not adjusted for this piecemeal aspect and the fair value of the system should be consistent in this manner.

Mr. Moody also believed it is not necessary to adjust his results for improvements in productivity as suggested by Mr. Kaufman. Moody Rebuttal, at 10. He testified that the Handy Whitman Index reflects these by the nature of its development. Generally speaking, each index is made up of either two or three major components that drive the cost of the type of asset being trended. For instance, the index for poles might be comprised of material (poles and cross arms), labor (skilled and common in some ratio) and vehicles. Mr. Moody stated that while it is true that there has been advancement in productivity in labor over the years due to the development of tools and supply systems, it also true that the same gains apply to the manufacture and delivery of manufactured materials. He said the same drivers that lower the relative cost of installation of poles (or any other asset) also lower the relative cost of converting raw materials into finished products. He asserted that as long as the ratio of the costs of the constituents of the index remains relatively similar with respect to one another, the index is a valid representation of the total cost of purchasing and installing the asset. He said the same concepts apply to technology. Mr. Moody pointed out that the Indiana Department of Local Government Finance advocates the use of the Handy Whitman Index for utility property, but does not require an adjustment for technology or productivity. *Id.* at 11.

Finally, Mr. Moody clarified that the Current Cost less depreciation portion of the fair value indicator includes the effects of historical inflation; the original cost less depreciation does not reflect any inflation.

(5) Commission Discussion and Findings. Ind. Code 8-1-2-6 establishes that this Commission shall value a public utility's property at its fair value. As noted by this Commission in its order on remand in Re Indianapolis Water Company, Cause No. 37612 dated July 3, 1986, 1986 Ind. PUC LEXIS 248, at *8, in Public Serv. Comm'n of Ind. v. City of Indianapolis, the Court gave the Commission the following four basic directives regarding the concept of "fair value":

(a) that it is the statutory "fair value" of the used and used property upon which the utility should be allowed to earn a return;

(b) that "fair value" is not an either/or situation as to original cost or reproduction cost new, but "fair value" is the conclusion or final figure drawn from all the various values or factors to be weighted in accordance with the statute by the Commission;

(c) that in its determination of fair value the Commission may not ignore the commonly known and recognized fact of inflation; and

(d) that while original cost was one of the factors which the Commission should consider in arriving at a "fair value" figure, it is not, in and of itself, an accurate reflection of the "fair value" of the Company's property.

The Court of Appeals has more recently confirmed that the Commission must authorize rates that provide the utility the opportunity to earn a fair return on the fair value of its property. Gary-Hobart Water Corp. v. Ind. Util. Reg. Comm'n, 591 N.E.2d 649, 653-54 (Ind. Ct. App. 1992); Office of Util. Consumer Counselor v. Gary-Hobart Water Corp., 650 N.E.2d 1201 (Ind. Ct. App. 1995).

Petitioner proposes that we find the fair value of its used and useful plant at $3,468,969,555. The genesis of this number is Petitioner's Witness Green's DCF analysis and Witness Moody's RCNLD study. There are at least two troubling inconsistencies among Petitioner's witnesses that work to undermine our confidence in the Petitioner's proposed fair value rate base calculation.

Mr. Green testified his DCF analysis values Petitioner's generating plants as if they were merchant plants with the ability to sell power into the wholesale market as opposed to regulated jurisdictional plants with the obligation to serve regulated customers. Unburdened by the public service obligation, merchant plants would be able to sell more power during more profitable periods. The result is an increased DCF value, producing a greater fair value rate base and ultimately a greater fair value increment. Mr. Moody, in discussing criticisms of his RCNLD study, argued that Petitioner's plant must be valued not as if it were rebuilt today (in the most efficient manner), but as individual components as they were originally constructed, because:

> ...the existing system was constructed in response to the needs of customers at the time of construction. Under the "regulatory pact", I&M is required to meet the needs of all its customers, even if it is a detriment to the efficiency of the existing system. I&M is promised an opportunity to recover these costs that were made in the public interest. Adjustments to the original cost contribution to fair value are not adjusted for this piecemeal aspect. The fair value of the system should be consistent in this manner.
>
> Moody Rebuttal, at 9-10.

Thus Mr. Moody argues the importance of evaluating Petitioner's system consistent with its obligation to serve (increasing RCNLD costs) while Mr. Green takes the opposite approach (increasing DCF results) – both to I&M's benefit.

Petitioner's depreciation witness Davis also provided testimony which appears to conflict with Mr. Moody, this time regarding negative salvage value associated with retiring and demolishing portions of I&M's generating plant. Mr. Kaufman argued that these costs will have negative impact on fair value. Kaufman Direct, at 69. Mr. Davis depreciation study reflects I&M's demolished generating plant with negative value and I&M's request for a higher depreciation rate (and expense) to recognize the increased demolition costs.

While Mr. Davis testified that I&M requires a higher depreciation rate and greater depreciation expense, Mr. Moody (Moody Rebuttal, at 9) testified:

> Furthermore, the market value of the generating plants was based on the actions of participants in the market for generating plants. In that market, plants are not typically demolished. The site and much of the infrastructure is redeveloped as another, new plant site which has significant value. <u>This value offsets any cost of removal of the portions of the plant not used by the purchaser</u>. <u>Underline added</u>.

The absence of demolition costs from Mr. Green's DCF analysis necessarily means that these impacts were not considered in calculating Petitioner's fair value rate base. We disagree with Petitioner's witness Moody's rebuttal argument that the plant retirement cost is not a rate base issue. Petitioner repeatedly argued that fair value is akin to market value, but here asks this Commission to believe that market value is immune to demolition costs. Witness Moody cites Cause No. 39314, Indiana – Michigan Power Company (11/12/93) for the proposition "evidence of market value is extremely important to the fair value process." That is precisely why market value must be estimated with great care. As we also stated in that Order at page 59:

> We may only speculate as to how a prospective purchaser would value a generating plant that by seller's own insistence would require demolition within a few years at a cost of millions of

> dollars. It is these types of considerations that make reproduction cost new analyses less than entirely persuasive as a best determinant of the fair value of utility property.

In *Duquesne*, the Court also recognized concerns with both estimating plant reproduction costs and the resulting fair value determination:

Although the fair value rule gives utilities strong incentive to manage their affairs well and provide efficient service to the public, it suffered from practical difficulties which ultimately led to its abandonment as a constitutional requirement. [footnote 5]

FN5: Perhaps the most serious problem associated with the fair value rule was the "laborious and baffling task of finding the present value of the utility." Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Comm'n, 262 U. S. 276, 262 U. S. 292-294 (1923) (Brandeis, J. dissenting). The exchange value of a utility's assets, such as power plants, could not be set by a market price, because such assets were rarely bought and sold. Nor could the capital assets be valued by the stream of income they produced, because setting that stream of income was the very object of the rate proceeding. According to Brandeis, the Smyth v. Ames test usually degenerated to proofs about how much it would cost to reconstruct the asset in question, a hopelessly hypothetical, complex, and inexact process. 262 U. S. at 262 U. S. 292-294.

Both OUCC witness Kaufman and IG witness Gorman testified that Petitioner's proposed fair value rate base contains defects that overstate Petitioner's proposed fair value rate base, including Mr. Green's DCF analysis valuing the generating plant. Mr. Kaufman pointed out that Mr. Green's DCF analysis relied on many assumptions including capital expenditures, capacity factors, reserve margins and electricity prices. A change to any of these assumptions would affect the results of Mr. Green's DCF analysis. Mr. Kaufman specifically pointed to capacity price increases as a factor that could influence the results of Mr. Green's DCF analysis. Kaufman Direct, at 68. Mr. Gorman criticized Mr. Green's market prices, capacity factors and capital expenditures outlined by Mr. Chodak. Gorman Direct, at 58. Many of the flaws pointed out by Messrs. Kaufman & Gorman would cause the results of Mr. Green's DCF analysis to be overstated.

Petitioner's RCNLD study does not reflect either increases in productivity or technological obsolescence. Kaufman Direct, at 70; Gorman Direct, at 58. Appropriate downward adjustments to RCNLD results should be made to account for efficiencies gained through improved technology/productivity. The Handy-Whitman index does not capture these efficiencies, as evidenced by adjustments made by experts testifying on behalf of utilities in other causes. Kaufman Direct, at 70-71.

Based on the totality of the evidence of record we conclude that Petitioner's fair value rate base is slightly above $2.9 billion, exceeding its original cost rate base, but less than Petitioner's proposed fair value rate base:

| | |
|---|---|
| Fair Value Plant | $ 2,766,000,000 |
| OPEB | $ 1,478,564 |
| 165 Prepaid Pension Expense | $ 0 |
| 253 Deferred Gain Rockport 2 Sale | $ (26,201,384) |
| 151 Fuel Stock | $ 47,809,575 |
| 156 Other Materials & Supplies | $ 116,080,081 |
| Fair Value Rate Base | |
| Indiana Jurisdictional | $ 2,905,166,836 |

**9. Fair Rate of Return and Net Operating Income.**

**A. Cost of Capital.**

(1) I&M Case-in-Chief. William E. Avera, Ph.D., President of FINCAP, Inc., presented his assessment of the rate of return on equity ("ROE") for I&M. He also addressed the reasonableness of I&M's capital structure, considering both the specific risks faced by I&M and other industry guidelines, and supported Petitioner's proposed fair return on fair value rate base that he asserted is consistent with underlying regulatory standards and the guidance of the Commission. Dr. Avera conducted various quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), an equity risk premium approach based on allowed rates of return, as well as reference to expected earned rates of return for utilities.

Based on the cost of equity estimates indicated by his analyses, Dr. Avera evaluated I&M's ROE taking into account the specific risks and potential challenges for its jurisdictional electric utility operations in Indiana, as well as other factors (*e.g.,* flotation costs) that are typically considered in estimating a fair rate of return on equity. Based on the results of his analyses and the economic requirements necessary to support continuous access to capital, Dr. Avera recommended a ROE for I&M from the middle of his 10.65% to 11.65% range, or 11.15%. Avera Direct, at 5.

Dr. Avera examined the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. Avera Direct, at 7. He explained that an understanding of the fundamental factors driving the risks and prospects of electric utilities is essential to develop an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return. Dr. Avera noted that currently, I&M is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P"), with Moody's Investors Service ("Moody's") assigning an issuer rating of "Baa2." Avera Direct, at 10. He stated that these ratings are identical to those assigned to I&M's parent, AEP. Meanwhile, Fitch Ratings Ltd. ("Fitch") has assigned a "BBB-" issuer default rating to I&M, while rating AEP one notch higher at "BBB." *Id.*

Dr. Avera argued implementation of structural change, along with other factors impacting the economy and the industry, has caused investors to re-think their assessment of the relative risks associated with the utility industry. Avera Direct, at 10. He asserted the past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. He showed that this view is supported by S&P and Moody's. *Id.* at 10-11. He stated I&M will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, fund new investment in electric generation, transmission and distribution facilities, and refinance scheduled debt maturities. *Id.* at 11. He pointed out AEP plans to invest $2.6 billion in utility assets during 2011 and $2.9 billion in 2012, while construction expenditures at I&M are anticipated to total approximately $305 million in 2011 alone. *Id.* Dr. Avera testified that support for the Company's financial integrity and flexibility will be instrumental in attracting the capital required to meet these fund needs in an effective manner. *Id.*

Dr. Avera also testified the potential for energy market volatility can be an ongoing concern for investors. Avera Direct, at 11. He stated that in recent years, utilities and their customers have had to contend with dramatic fluctuations in fuel costs due to ongoing price volatility in the spot markets, and investors recognize the potential for further turmoil in energy markets. He stated that in times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. *Id.* at 11-12. He added that coal has historically provided relative stability with respect to fuel costs, but prices experienced significant volatility over the 2007 -2009 time period.

Dr. Avera also discussed other pressures that impact investors' risk assessment of I&M. *Id.* at 13. He noted that investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments and noted that both S&P and Moody's has observed that cost increases and capital projects, along with uncertain load growth, are a significant challenge to the utility industry. He noted that investors are aware that I&M and AEP will undertake significant electric utility capital expenditures. Dr Avera explained that investors are aware that utilities, including I&M, are confronting increased environmental pressures that impose significant uncertainties and costs. *Id.* at 13. He stated that while customers benefit from the advantages of fuel cost savings and diversity that nuclear power confers, investors associate nuclear facilities with risks that are not encountered with other sources of generation. *Id.* at 14-15. He added that these concerns have been exacerbated by the events at the Fukushima Daiichi nuclear complex in Japan. *Id.* at 15. Dr. Avera testified that Moody's cited the importance of a constructive regulatory relationship and "a need to establish financial policies over the near-term aimed at producing very strong financial credit ratios in order to maintain a given rating" as necessary to mitigate against these potential exposures. *Id.* at 16.

Dr. Avera also discussed the implications of recent capital market conditions. *Id.* at 16. He explained that the deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase. *Id.* at 16-18. Dr. Avera provided support for his view, including references to industry publications. He argued that uncertainties surrounding economic and capital market conditions heighten the risks faced by electric utilities, which, as described earlier, face a variety of operating and financial challenges.

Dr. Avera presented a comparison of interest rates on long-term bonds to those projected for the next few years. *Id.* at 18-19. According to Dr. Avera, this comparison showed that there is a consensus that the cost of permanent capital will be higher in the 2012-2015 timeframe. Dr. Avera argued that as a result, current cost of capital estimates are conservative, and likely understate investors' requirements at the time the rates set in this proceeding become effective. *Id.*

Dr. Avera discussed what these events imply with respect to the ROE for I&M. He explained that no one knows the future of our complex global economy. *Id.* at 19. He explained that we know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. He stated that while conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. *Id.* at 19-20. He added the fact remains that the electric utility industry requires significant new capital investment. Given the importance of reliable electric utility service, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case. *Id.* at 20. He stated the Company's capital structure must also preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions. *Id.*

Dr. Avera explained that the fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.,* U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. *Id.* at 21. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them. *Id.* Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk. *Id.*

Dr. Avera testified that there is evidence that the risk-return tradeoff principle actually operates in the capital markets. *Id.* at 22. He stated that the risk-return tradeoff can be documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. *Id.* He stated that the observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets. *Id.*

He explained that it is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. He added that documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets - including common stock - required rates of return cannot be directly observed. Yet, there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities. *Id.*

Dr. Avera explained that the risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. *Id.* He stated that the securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. He explained that the last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt. *Id.* at 23.

Dr. Avera explained what this implies with respect to estimating the cost of common equity for a utility. He stated that although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. *Id.* Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. He said these various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data. *Id.*

Dr. Avera testified that he did not rely on a single method to estimate the cost of common equity for I&M. In his opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. *Id.* Therefore, he applied both the DCF and CAPM methods to estimate the cost of common equity, and considered the results of the risk premium and expected earnings approaches. In his opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic. *Id.* Dr. Avera explained that the alternative approaches that he applied to estimate the cost of common equity have theoretical and practical support, and the body of knowledge on the topic of cost of capital attests to the significance of developing cost of capital estimates that work in the real world of financial markets. *Id.* at 24. For example, the reality that investors require compensation for bearing the risk of putting their money in common stock is a fundamental tenet of the theory and practice of finance. He noted that while assumptions and judgment underlie these methods to estimate the cost of common equity, this does not imply that they are subjective or that the cost of common equity is unknowable. *Id.*

Dr. Avera explained each method of estimating the cost of common equity is based on empirical evidence and accepted applications. *Id.* While experts may disagree on particular nuances and details of their application, the reliability of these methods is confirmed by their use throughout the regulatory arena as well as in the worlds of investment management and corporate finance. The fact that alternative methods may give somewhat different results, or that different experts may come to different estimates using these methods, does not mean the methods are subjective or unreliable. It means simply that interpreting the results of these methods requires care and practical judgment. *Id.*

Dr. Avera also evaluated the reasonableness of I&M's requested capital structure and examined the implications of cost adjustment mechanisms for the Company's ROE. *Id.* at 61-62. He concluded that a common equity ratio of approximately 52 percent represents a reasonable capitalization for I&M. He explained that the common equity ratio implied by I&M's capital structure is consistent with the range of book value capitalizations maintained by the proxy group of electric utilities, and falls below the average market value equity ratios for the proxy group, based on data at year-end 2010 and near-term expectations. *Id.* at 6, 65-70. He added that his conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks and the pressures of funding significant capital investments, as well as the impact of off-balance sheet commitments such as I&M's obligations under operating leases.

(a) Comparable Risk Proxy Groups. Dr. Avera explained that application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Avera Direct, at 25. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable. *Id.*

In order to reflect the risks and prospects associated with I&M's jurisdictional utility operations, Dr. Avera's DCF analyses focused on a reference group of other utilities composed of those companies classified by Value Line as electric utilities with: (1) an S&P corporate credit rating of "BBB-" to "BBB+", (2) a Value Line Safety Rank of "2" or "3", (3) a Value line Financial Strength Rating of "B+" to "A", and (4) a market capitalization of approximately $1.8 billion or greater. Avera Direct, at 25. In addition, he eliminated four utilities that are involved in a major merger or acquisition. These criteria resulted in a proxy group composed of twenty-four companies, which he referred to as the "Utility Proxy Group." *Id.* at 25.

He testified that under the regulatory standards established by *Hope* and *Bluefield,* the salient criterion in establishing a meaningful benchmark to evaluate a fair ROE is relative risk, not the particular business activity or degree of regulation. *Id.* at 26. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, he also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. Dr. Avera referred to this group as the "Non-Utility Proxy Group." *Id.*

He explained that utilities compete with non-regulated firms for capital. *Id.* at 26. He stated that the cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Dr. Avera testified the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. *Id.*

Dr. Avera asserted that returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. He testified that the Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings which are attended by corresponding risks and uncertainties." *Bluefield* at 679. It does not restrict consideration to other utilities. Similarly, the *Hope* case states: "By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." *Hope* at 288. As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry. Dr. Avera observed that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision, regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies. *Id.* at 27.

Dr. Avera testified that consideration of the results for the Non-Utility Proxy Group makes the estimated of the cost of equity using the DCF model more reliable. He argued that the estimates of growth from the DCF model depend on analysts' forecasts. *Id.* He stated that it is possible for utility growth rates to be distorted by short-term trends in the industry or the industry falling into favor or disfavor by analysts. He said the result of such distortions would be to bias the DCF estimates for utilities. *Id.* He contended that because his Non-Utility Proxy Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector. *Id.* at 28.

Dr. Avera opined that reference to his Non-Utility Proxy Group incorporates companies where the original cost of investment is largely irrelevant in determining market performance. Moreover, the earnings they can generate in the future dictate the value of a company's assets in the unregulated sector. Hence, the required return on equity for unregulated companies is a relevant benchmark for the required return on equity under the fair value standard of regulation. *Id*

Dr. Avera's comparable risk proxy group of non-utility firms was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or greater; (4) have a beta of 0.85 or less; and, (5) have investment grade credit ratings from S&P. *Id.* He testified that these criteria provide objective evidence to evaluate investors' risk perceptions. *Id.* at 29. He explained that credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to 0 (in default). Other symbols *(e.g.,* "A+") are used to show relative standing within a category. *Id.* He stated that because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. He stated that although the credit rating agencies are not immune to criticism, their rankings and analyses are widely cited in the investment community and referenced by investors. Investment restrictions tied to credit ratings continue to influence capital flows, and credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity. *Id*

Dr. Avera testified that while credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). *Id.* He said this overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. *Id.* He added that given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

He testified that the Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. *Id.* at 30. He stated that Value Line's beta is an objective, published indicator that measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. *Id.*

Dr. Avera compared the overall risk of his proxy groups with I&M. This comparison indicated that investors would view the firms in his proxy groups as having risk comparable to I&M. *Id.*

(b) Discounted Cash Flow Analyses. Dr. Avera explained that DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. Avera Direct, at 31. He stated that the model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. Dr. Avera stated that by estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock.

Dr. Avera explained that rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form. *Id.* at 32. He pointed out that the constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. *Id.* at n. 34. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.,* no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. He explained that this constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield; and, 2) growth. Avera

Direct, at 33. In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Dr. Avera applied the constant growth DCF model to estimate the cost of common equity for I&M, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators. *Id.* at 33.

He explained that the first step to implement the constant growth DCF model is to determine the expected dividend yield for the firm in question. He explained that this is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. He said the next step is to evaluate long-term growth expectations, for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. He noted that implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. Dr. Avera said a wide variety of techniques can be used to derive growth rates, but the only growth rate that matters in applying the DCF model is the value that investors expect. *Id.* at 34.

Dr. Avera also testified that historical growth rates are unlikely to be representative of investors' expectations for utilities. *Id.* He said if past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. He stated that is clearly not the case for utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. *Id.* Dr. Avera testified that while these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or the expectations that investors have incorporated into current market prices. Because past trends for utilities do not currently meet the requirements of the DCF model, Dr. Avera's DCF analysis did not reference historical growth rates. Instead, he focused exclusively on indicators of future growth in applying his DCF model. *Id.* at 35.

Dr. Avera argued that while the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. *Id.* In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry. He asserted that as a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties. He stated that as payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Dr. Avera testified that future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. He testified that the importance of earnings in evaluating investors' expectations and requirements is well accepted. *Id.* at 35-36. He stated the fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. *Id.* at 36.

Dr. Avera acknowledged that professional security analysts study historical trends extensively to develop their projections of future earnings. Hence, he argued to the extent there is any useful information in historical patterns, that information is already incorporated into analysts' growth forecasts. *Id.* at 37. He argued that in applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information. *Id.* at 38.

He stated any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. Dr. Avera contended if financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. Dr. Avera added the reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (*e.g.*, Value Line) implies that investors use them as a basis for their expectations. *Id.* at 38. He said the continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. *Id.*

He stated that while the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices and any bias in analysts' forecasts - whether pessimistic or optimistic - is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. *Id.* at 38-39.

Dr. Avera explained that in constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, Dr. Avera testified that this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings. *Id.* at 39. Accordingly, while Dr. Avera believes that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, he included the "sustainable growth" approach in his presentation for completeness. *Id.* at 40.

Dr. Avera testified that in applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method. *Id.* at 41-46. He stated that FERC applies a similar approach. *Id.* at 42-43. Dr. Avera's application of the constant growth DCF model results in cost of common equity estimates for his Utility Proxy Group ranging from 9.5% to 11.5 %. *Id.* at 46. His analysis resulted in of common equity estimate for his Non-Utility Proxy Group ranging from 11.7% to 12.3%. *Id.* at 47.

(c) Capital Asset Pricing Model. As explained by Dr. Avera, the CAPM is generally considered to be the most widely referenced method to estimate cost of equity among academicians and professional practitioners outside the regulatory sphere, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Avera Direct, at 48. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.,* common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. *Id.* As Dr. Avera also explained, like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data. *Id.* at 49.

Dr. Avera explained how he applied the CAPM to estimate a forward-looking estimate for investor's required rate of return from common stocks. *Id.* at 49-50. He asserted that because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect. *Id.* at 50. He stated that according to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, *Morningstar* (Ibbotson SBBI 2010 Valuation Yearbook) has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. Accordingly, Dr. Avera's CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups. *Id.* at 50-51. He stated that the application of his CAPM approach resulted in an unadjusted ROE of 10.9% for his Utility Proxy Group and an adjusted ROE of 11.7% when the size adjustment is incorporated. *Id.* at 51. For his Non-Utility Proxy Group, Dr. Avera's CAPM approach resulted in an average implied cost of common equity of 10.6 percent, or 10.3 percent after adjusting for the impact of firm size. *Id.* at 51-52.

Dr. Avera explained that it is appropriate to consider anticipated capital market changes in applying the CAPM. *Id.* at 52. As he claimed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. Dr. Avera stated that as a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, he also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. Dr. Avera stated that incorporating a forecasted Treasury bond yield for 2012-2015 implied an unadjusted cost of equity of approximately 11.2% for his Utility Proxy Group, or 12.0% after accounting for firm size. *Id.* at 52. For his Non-Utility Proxy Group. Dr. Avera's application of the CAPM using a projected government bond yield resulted in cost of equity estimate of 10.9% and 10.6% before and after adjustment for firm size, respectively. *Id.*

Dr. Avera discussed why he believed the CAPM approach should not be applied using historical rates of return. *Id.* He said the CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. He asserted that in response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. He said this distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Dr. Avera opined economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. Dr. Avera stated that at no time in recent history has the fallacy of this assumption been demonstrated more concretely. He said this incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. *Id.* at 53.

(d) Risk Premium Approach. The risk premium method of estimating investors' required rate of return extends to common stocks the risk-return tradeoff observed with bonds. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. Avera Direct, at 53. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields. *Id.* at 54.

Dr. Avera based his estimates of equity risk premiums for electric utilities on surveys of previously authorized rates of return on common equity. *Id.* He said authorized returns presumably reflect regulatory commissions' estimates of the cost of equity, however determined, at the time they issued their final order. He stated that such returns should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, Dr. Avera opined this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities. Dr. Avera testified that surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. *Id.* The rates of return on common equity authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. *Id.* In his analysis, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and

2010. Over this 37-year period, these equity risk premiums for electric utilities averaged 3.36% and the yield on public utility bonds averaged 9.01% *Id.*

Dr. Avera said there is a capital market relationship that must be considered when implementing the risk premium method. *Id.* at 55. He explained there is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. He said the implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. *Id.* Accordingly, Dr. Avera explained that for a 1 percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated. Dr. Avera added that it is important to recognize that the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing electric utility service. As a result, Dr Avera asserted they are likely to understate the cost of equity for a firm operating in today's electric power industry. *Id.*

Based on the regression output between the interest rates and equity risk premiums displayed in his exhibit, Dr. Avera testified that the equity risk premium for electric utilities increased approximately 41 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Petitioner's Exhibit WEA-8, with the yield on average public utility bonds in July 2011 being 5.34% he said this implied a current equity risk premium of 4.86% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 5.70% produces a current cost of equity of approximately 10.6%. *Id.* at 56. As shown on page 2 of Petitioner's Exhibit WEA-8, incorporating a forecasted yield for 2012-2015 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.29% for electric utilities. Dr. Avera explained that adding this equity risk premium to the average implied yield on triple-B public utility bonds for 2012-2015 of 7.10% resulted in an implied cost of equity of approximately 11.4% *Id.*

(e) Expected Earnings Approach. Dr. Avera also evaluated the cost of common equity using an expected earnings method. Avera Direct, at 56. He contended that reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. He testified that this expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope.* Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

He said the simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. *Id.* at 57. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation.

Dr. Avera testified that the traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. *Id.* He said the actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.,* Value Line). *Id.* He stated that because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Dr. Avera pointed out that regulators do not set the returns that investors earn in the capital markets - they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. *Id.* As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. *Id.* at 57-58. Dr. Avera stated that this opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. Dr. Avera claimed as long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior. Dr. Avera testified that the average ROE indicated for electric utilities based on the expected earnings approach range from 10.5% to 10.7%. *Id.* at 58.

(f) Flotation Costs. Dr. Avera testified that flotation costs are also relevant in setting the ROE for a utility. Avera Direct, at 59. He testified that the common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. *Id.* He said these flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity. *Id.*

Dr. Avera stated that there is not an established mechanism for a utility to recognize equity issuance costs. *Id.* at 59-60. He explained that while debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. He testified that equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Thus, unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. He testified because there is no accounting convention to accumulate the flotation costs associated with equity issues, these costs must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism. *Id.* at 59-60.

Dr. Avera put forth that while there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. *Id.* at 60. Dr. Avera noted that *New Regulatory Finance* concluded that: "The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue." *Id.* He said, alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%. Dr. Avera added that AEP incurred issuance costs equal to approximately 3.02% of the gross proceeds from its 2009 public offering of common stock. *Id.* He testified that applying this 3.02% expense percentage to a representative dividend yield of 5.0% implies a minimum flotation cost adjustment on the order of 15 basis points. *Id.*

(g) Impact of Rate Adjustment Mechanisms. Dr. Avera asserted the FAC and other rate adjustment mechanisms used by I&M do not warrant any adjustment in his evaluation of a fair ROE. Avera Direct, at 72-73. He said investors recognize that I&M is exposed to significant risks associated with energy price volatility and rising costs and concerns over these risks have become increasingly pronounced in the industry. He said that while the FAC is supportive of the Company's financial integrity, even for utilities with energy cost adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from ratepayers. Thus, the FAC does not insulate I&M from the need to finance significant deferred power production and supply costs. He added that investors are also aware that the Company's fuel cost recovery may be adversely affected by the operating expense and return tests applicable to its FAC, which may result in an effective disallowance of fuel costs. *Id.* at 72.

He testified that the rate adjustment mechanisms do not imply that the Company's risks are lower than for other utilities in the nation or for those in the proxy groups used in his quantitative analysis. *Id.* at 72-73. He opined that adjustment mechanisms and trackers have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as energy conservation, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers in favor of reducing consumption through decoupling and other adjustment mechanisms. He stated that while they are not always directly analogous to the specific mechanisms approved for I&M, the objective is similar; namely, to allow the utility an opportunity to earn a fair rate of return and mitigate exposure to attrition in an era of rising costs. *Id.* As a result, the mitigation in risks associated with utilities' ability to attenuate the risk of cost recovery is already reflected in the cost of equity range determined earlier. Similarly, Dr. Avera argued that the firms in his Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. *Id.* at 73.

(h) Recommended ROE. Dr. Avera discussed the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, Dr. Avera used both the DCF and CAPM methods to estimate a fair ROE for I&M, and considered the results of the risk premium and expected earnings approaches. Avera Direct, at 73. In order to reflect the risks and prospects associated with the Company's jurisdictional utility operations, his analyses focused on a proxy group of other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, he also referenced a proxy group of comparable risk companies in the non-utility sector of the economy. He said that considering the relative strengths and weaknesses inherent in each method and conservatively giving less emphasis to the upper- and lower- most boundaries of the range of results, he concluded that the cost of common equity indicated by his analyses is in the 10.5% to 11.5% range. After incorporating an adjustment for flotation costs of 15 basis points to his cost of equity range, he concluded that a fair rate of return on equity for his proxy group of electric utilities is currently in the 10.65% to 11.65%.

Dr. Avera recommended a ROE for I&M at the midpoint of his range, or 11.15%. *Id.* at 74-75. He said apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting the Company's financial position so that I&M remains prepared to respond to unforeseen events that may materialize in the future. He stated recent challenges in the economic and financial market environment highlight the imperative of maintaining the Company's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers. Dr. Avera asserted because nuclear power represents a significant portion of the Company's generating capability, I&M is exposed to significant financial threats. In addition, I&M faces ongoing uncertainties related to future emissions legislation. Coupled with the need to provide an ROE that supports I&M's credit standing while funding necessary system investments, Dr. Avera testified that these considerations indicate that an ROE from the middle of his recommended range is reasonable.

Dr. Avera added that I&M has distinguished itself in numerous measures of operating efficiency and effectiveness while maintaining moderate electric rates. As a result, consumers in I&M's service area have benefited from efficient and cost-effective operations, excellent customer service, and reliable electric service. Considering the Company's superior performance, Dr. Avera concluded that establishing a ROE of 11.15% for I&M is entirely consistent with regulatory economics. *Id.* at 75.

(2) <u>OUCC Case-in-Chief.</u> OUCC Witness Edward R. Kaufman, CRRA, presented the OUCC's proposed cost of equity ("COE") analysis, recommending the Commission authorize a 9.2% cost of equity for Petitioner. Mr. Kaufman offered both support for his estimate and discussion of flaws in Dr. Avera's cost of equity testimony. Kaufman Direct, at 3, 35-60.

Mr. Kaufman used both a Discounted Cash Flow ("DCF") and a Capital Asset Pricing Model ("CAPM") analysis to estimate Petitioner's cost of equity. His DCF model produced a range of estimates from 9.31% to 9.51% and his CAPM analysis produced a range of estimates from 6.58% to 6.87%. Mr. Kaufman explained that his recommended 9.20% cost of common equity results in a weighted cost of capital of 6.35% (OUCC Schedule MDE-7, sponsored by OUCC witness Michael Eckert).

Mr. Kaufman explained the primary differences between he and Dr. Avera in this case were the model inputs, the weight given to each model, and adjustments Dr. Avera makes to his models. Mr. Kaufman also explained that cost of equity is lower today than it was at the time of Petitioner's last rate case. Mr. Kaufman stated that both cost of debt and the industry beta had declined since I&M's last rate case. Mr. Kaufman's recommendation was 195 basis points less than Dr. Avera's, a range similar to their respective positions in I&M's last rate case – 9.5% vs. 11.5%. Kaufman Direct, at 3.

Mr. Kaufman then observed that interest rates are at historically low levels, concluding that lower interest rates translate directly into a lower cost of equity. Long-term capital costs, like interest rates, are as low or are lower today than they have been during most of the last 50 years, so Mr. Kaufman opined Petitioner's cost of equity should reflect these circumstances.

(a) Comparable Risk Proxy Groups. Mr. Kaufman observed that because neither the DCF model nor the CAPM can be directly applied to Indiana-Michigan Power Company, a proxy group of publically traded companies is necessary to estimate Petitioner's cost of equity. Mr. Kaufman explained that American Electric Power (Petitioner's parent company) derived 93% of its revenues from regulated electric operations, and that reasonable comparability ought to require proxy group members to derive at least a majority of its revenues from regulated electric utility operations; how the companies make their money is central to any decision on comparability. Mr. Kaufman further explained that even if other risk metrics are similar, electric utility operations have their own risk characteristics (such as trackers) and therefore, he removed the following companies from Dr. Avera's electric utility proxy group, (Regulated Electric revenue %s from March, 2012 AUS Utility Reports):

Constellation Energy (17%),
Integrys Energy Group (27%),
Sempra Energy (27%) and
Public Service Enterprise Group (44%).

Mr. Kaufman also eliminated two other companies: ITC Holdings Corp. (a pure transmission company) and CMS Energy (28.3% equity ratio). Compared to Petitioner's 52.97% equity ratio (MDE-7 page 3), CMS Energy carries a measurably higher financial risk. These two companies are also the only two members of Dr. Avera's proposed proxy group with an equity ratio of less than 40.0%. Avera Exhibit WEA-10.

Regarding Dr. Avera's use of a non-utility proxy group, Mr. Kaufman expressed his concern that the 53 companies in Dr. Avera's non-utility proxy group do not share "reasonably comparable" risk with either Petitioner or the electric utility industry. State regulation influences the risks of utilities. Moreover, the expanded use and effectiveness of trackers reduces the risk of both Petitioner and the electric utility industry. While this reduction in risk may be incorporated into an electric utility proxy group, it is not incorporated into a non-utility proxy group. Mr. Kaufman then proved that several of Dr. Avera's non-utility proxy group members had unusual risk characteristics that made them inappropriate to estimate Petitioner's cost of equity. Mr.

Kaufman concluded the Commission should not give any weight to Dr. Avera's analysis of a non-utility proxy group and going forward his critique discussed only Dr. Avera's utility proxy group analyses. Kaufman Direct, at 36.

(b) DCF Analyses. Mr. Kaufman discussed his single stage DCF model's mechanics and how it was used. Combining a traditional single stage DCF and Value Line's historical and forecasted growth rates of earnings per share, dividends per share and book value per share, he estimated a 5.13% growth rate. Kaufman Direct, at 14. Mr. Kaufman also used a single stage DCF model with forecasted growth rates of earnings per share from Value Line, Yahoo.com (which relies on I/B/E/S Thomson Financial) and Zacks to determine an estimated growth rate of 5.30%. *Id*

In both single-stage DCF analyses Mr. Kaufman eliminated zero and negative growth rates, consistent with the Commission's Order in Cause No. 40103. *Id.* at 15. He did not eliminate low positive growth rates as he explained that low growth rates are not ignored by investors. Mr. Kaufman also explained that he did not eliminate high positive growth rates either. He stated that his growth rate of 5.13% is supported by a Value Line chart titled *A Long Term Perspective,* which provides average growth rates in earnings per share, dividends per share and book value per share. He stated that the average growth rate for each of these measures for the Dow Jones Industrial Average was similar to 5.13% from 1920 – 2005, and thus, while somewhat dated, helped support his use of a growth rate of 5.19% in his Value Line DCF analysis. *Id.* at 16.

Discussing his 2-stage DCF analysis, Mr. Kaufman asserted that short- to intermediate-term forecasts can lead to unreasonably high estimated growth rates in a DCF analysis, and should not be mechanically incorporated into a DCF analysis. To support his claim, Mr. Kaufman cited to a 2003 article published in the National Regulatory Research Journal ("NRRI") of Applied Regulation which stated that no utility can sustain a growth rate over the long run that exceeds the growth rate of the economy. Mr. Kaufman further cited a 2003 Wall Street Journal article as indicating that analysts' forecasts are potentially biased upwards due to possible financial incentives. Along with the Wall Street Journal article Mr. Kaufman also cited to two articles by McKinsey Quarterly to further support his opinion that analyst forecasts were bullish. *Id.*, at Appendix A. Mr. Kaufman concluded that both the potential for analyst bias and the intermediate term nature of analyst forecasts of earnings per share may make these estimates potentially unreliable. Mr. Kaufman asserted even assuming no analyst bias, unsustainable growth rates should be adjusted or given reduced weight. *Id.* at 16.

Mr. Kaufman stated that a two-stage DCF model can give appropriate weight to short term or intermediate term forecasts in earnings per share to estimate the cost of equity. He explained the model mechanics and how he used inputs from Mr. Moul's single stage DCF analysis as part of the two-stage DCF. *Id.* at 17. Using a dividend yield of 4.25%, a near term dividend growth rate of 6.17% and the long-term EPS growth rate of 4.75%, his 2-stage DCF produced an estimated cost of equity of 9.49%. *Id.* at 18. Mr. Kaufman explained why it is reasonable to use the U.S. economy forecasted growth rate as a long term sustainable rate and cited several sources to support his estimate of 4.75%. *Id.* at 19. Mr. Kaufman also completed a second 2-stage DCF model based on Value Line, Zacks and Yahoo.com forecasted growth rates in EPS. This analysis produced an estimated cost of equity of 9.31%. Mr. Kaufman explained that he used his 2-stage DCF model as a check to the results of his single stage DCF analysis and that he gave more weight to his single stage DCF analysis.

Mr. Kaufman expressed concerns with Dr. Avera's DCF, in particular his use of forecasted growth rate. Mr. Kaufman warned that a DCF analysis based exclusively or primarily on forecasted growth in EPS may overstate cost of equity. Forecasted EPS estimates are not long term (perpetual) estimates. So-called "long-term" EPS estimates provided by companies offering them are typically for only three to five years. This timeframe does not necessarily represent a reasonable long term estimate. Moreover, analyst EPS forecasts tend to be optimistic, overstate long term growth and should not be used in isolation. Mr. Kaufman then cited several texts (collected in his Appendix E) supporting his position. Mr. Kaufman concluded, this Commission should, as it had in Indiana-American (Cause No. 43860) and many other cases, review and give weight to both historical and forecasted data of growth rates in EPS, DPS and BVPS. Kaufman Direct, at 40.

(c) <u>CAPM Analysis</u>. Presenting his CAPM analysis, Mr. Kaufman indicated the model is typically more controversial and less reliable than the DCF, and that different applications of CAPM may cause vastly different cost of equity estimates. Kaufman Direct, at 22. He testified that the geometric mean is a better approach to determine the risk premium than an arithmetic mean – citing several supporting articles in Appendix B of his direct - but that his CAPM analysis considers both. Mr. Kaufman explained that the Commission has consistently given weight to both the arithmetic mean risk premium and the geometric mean risk premium, including Petitioner's most recent rate case, Cause No. 43680. *Id.* at 25.

Mr. Kaufman stated that he also developed a forecasted risk premium in addition to his historical risk premium because the latter is below the historical averages. *Id.* at 26-27. Based upon his review of a number of articles in his Appendix C, forecasting market risk premiums between 1.5 to 5.25%, Mr. Kaufman selected the top end of the range as his CAPM's forecasted risk premium. *Id.* at 29. He noted that at this time, he places more weight on the historical risk premium. Mr. Kaufman testified that the cost of equity based on his CAPM analysis using a historical risk premium ranged from 6.58% to 6.61%, and the cost of equity based on his CAPM analysis using a forecasted risk premium ranged from 6.83% to 6.87%. *Id.* at 31.

Mr. Kaufman's specifically disagreed with Dr. Avera's market risk premium, his use of projected bond yields and his use of a size adjustment in the CAPM. Mr. Kaufman confirmed that Dr. Avera's CAPM relied on an estimated market return of 13.2% to estimate his market risk premium. Mr. Kaufman explained why Dr. Avera's 13.2% estimated market return is unreasonably high. Mr. Kaufman testified that using only an arithmetic mean return, the average historical market return for 1926 through 2011 is 11.80%. Thus, Dr. Avera's analysis assumes a total market return 140 basis points higher than the arithmetic average return earned over the last 86 years. Dr. Avera's estimated market return is also 340 basis points above the compound (geometric) annual return of 9.8% over the same time period. Mr. Kaufman cited several credible sources estimating expected market returns at or around 9.0% (including Petitioner's own actuary and its NISA, who manages I&M's NDT). Kaufman Direct, at 35.

Mr. Kaufman further explained that Dr. Avera uses a DCF methodology to estimate a market return. Because this method relies solely on intermediate term forecasted growth in EPS to estimate (g) growth, it inescapably must suffer from the same flaws that Mr. Kaufman explained in his earlier critique of Dr. Avera's DCF analysis. First, intermediate term forecasted growth in EPS are not long term estimates, they may not be sustainable (especially when they exceed the long term estimate of the US economy), they may be upwardly biased and one should not rely on any single estimate of growth. Dr. Avera's 10.9% average forecasted EPS growth suffers from all of these deficiencies. Mr. Kaufman noted that when evaluating a DCF analysis, the Commission has consistently found that the growth rate must be realistic and should rely on multiple estimates of (g). The same principle applies when using a DCF model to estimate a total market return in a CAPM analysis. Kaufman Direct, at 46.

Mr. Kaufman's expressed concern with Dr. Avera's CAPM "current interest rate," focusing on its dramatic drop after Dr. Avera filed his direct testimony. Next, Mr. Kaufman demonstrated that Dr. Avera's CAPM analysis produced unusual results. Mr. Kaufman pointed out that when beta (B) is 1.0, Dr. Avera's inputs produce results that are completely insensitive to changes in interest rates. Worse, when beta exceeds 1.0, Dr. Avera's CAPM's estimated cost of equity <u>actually declines as the interest rate increases</u>.

Mr. Kaufman testified that using forecasted interest rates in a CAPM analysis (as Dr. Avera did) does not provide meaningful insight to estimate Petitioner's cost of equity. Because the purchase price produces a yield that the investor is willing to accept over the life of the debt, the current yield on long term debt is already a forward-looking yield over the investment horizon. Kaufman Direct, at 48. Mr. Kaufman pointed out that forecasting an increase to bond yields includes an unstated, yet crucial corollary – the bond's price will decrease. The only way for a bond's yield to increase is for the bond price to decrease. *Id.* at 49. By way of example, he demonstrated that if a 30-year bond purchased for $1,000 with a 5.0% interest rate has its yield forecasted to increase from 5% to 6% at the beginning of year 3, the forecaster is simultaneously forecasting that the value of that bond will decrease by approximately $134 to $864. *Id.* at Schedule ERK- 4, page 2. Potential bond purchasers that accept the forecast will not pay $1000 today for a bond they forecast will be worth $864 two years from now. Buyers will decrease the current purchase price and the spread between the forecasted yield and current yield will decrease. *Id.* at 49. When the bond is actually bought, investors are affirming the current yield over the life of the bond. Thus any current yield reflects a purchase price that incorporates any forecasted increase in future yields. Mr. Kaufman also revealed that financial sources such as Value Line have consistently forecasted increasing interest rates.

Mr. Kaufman emphasized Dr. Avera's proposed 81 basis point small company risk adjustment was unnecessary and overstated Petitioner's cost of equity. Mr. Kaufman explained Ibbotson's equity size premium adjustment is based on the theory that smaller companies have earned returns above what would otherwise be predicted by a CAPM analysis. It is not appropriate to directly apply Ibbotson's equity size premium adjustment to regulated utilities as regulation decreases the risks faced by Petitioner and Dr. Avera's electric utility proxy group. These companies also do not face the same bankruptcy risks as other similarly sized companies. Mr. Kaufman then pointed to academic articles and prior Commission orders to support his testimony that it was unnecessary to increase Petitioner's cost of equity to account for a small company risk adjustment.

Mr. Kaufman pointed out that interest rates had declined by more than 100 basis points since both Dr. Avera's Capital Asset Pricing Model were filed. CAPM results decline point-for-point as interest rates decline, all other things equal.

(d) Risk Premium Approach. Mr. Kaufman challenged the value of Dr. Avera's Risk Premium model, testifying that using commission-authorized costs of equity is not appropriate to estimate a required rate of return. Commission-authorized returns are the result of a cost of equity analysis and they should not be used as an input to the analysis. The direct use of prior costs of equity makes the model circular. Mr. Kaufman also noted that forecasted interest rates were equally inappropriate in a Risk Premium model as they were in a CAPM analysis. Mr. Kaufman affirmed that there is a further concern about using forecasted bond yields in his Risk Premium model. The risk premium that Dr. Avera calculates is based on current bond yields. If one is going to use a forecasted bond yield as an adder to the premium, then one should also use forecasted bond yields to calculate the premium. Kaufman Direct, at 54. Mr. Kaufman noted that the decline in interest rates affects the Risk Premium model in the same fashion as the CAPM – as interest rates fall, so do the Risk Premium model results.

(e) Expected Earnings Approach. Mr. Kaufman revealed that Dr. Avera's Expected Earnings approach was simply a compilation of Value Line's 3-5 year estimated return on common equity. These forecasted returns were neither a required return nor a cost of equity, but rather an intermediate term forecast. Mr. Kaufman explained that if a company was forecasted to over/under earn during the forecast period, using that figure to determine an authorized cost of equity would simply reinforce out-of-place expectations into future rates. Kaufman Direct, at 55. Mr. Kaufman also reiterated his concerns regarding Dr. Avera's utility proxy group.

(f) Flotation Costs. Mr. Kaufman explained why Dr. Avera's proposed flotation cost adjustment was not justified in this case. When a utility has recently incurred or expects to incur flotation costs in the near future, this Commission has typically allowed utilities to recover measurable and reasonable flotation costs. Because Petitioner has not demonstrated a near term need, nor have they recently issued equity, Mr. Kaufman did not believe it was necessary to include a flotation cost adjustment for Petitioner's proposed cost of equity at that time. Kaufman Direct, at 57.

(g) Impact of Rate Adjustment Mechanisms. Mr. Kaufman testified that he did not make a specific adjustment to his proposed cost of equity to account for trackers. He explained that the increased use and effectiveness of trackers was still relevant to estimate Petitioner's cost of equity. According to Mr. Kaufman, the decreased risk in trackers is properly reflected in the results of his DCF and CAPM analyses. He also explained that the expanded use and effectiveness of trackers calls into question the relevance of using a proxy group of unregulated companies. Kaufman Direct, at 6-7.

(h) Recommended ROE. Mr. Kaufman's cost of equity models produced a range of equity estimates of 6.58% to 9.51% with a midpoint of 8.05%. He explained that it was appropriate to give more weight to models in a manner consistent with past Commission orders. Mr. Kaufman recommended a cost of equity near the high end of his range. Based on his DCF and CAPM analyses, Mr. Kaufman recommended a cost of equity of 9.2%.

He explained that there was no need to adjust the results of his proxy group's cost of equity to make it applicable to Indiana Michigan as he believed they had similar business and financial risk to the companies in the proxy group. Mr. Kaufman explained that his models incorporate inputs and methodologies explicitly approved by this Commission in countless previous cases

Mr. Kaufman established that several sources, including Petitioner's own actuary, forecasted expected long term returns for the market consistent with his proposed 9.2% cost of equity, and was reasonable in today's markets. First Mr. Kaufman described that both current and forecasted inflation were at historically low levels. Kaufman Direct, at 32-33. Mr. Kaufman then cited to several sources, including the Duke CFO survey, the Schwab Center for Financial Research, an article from Portfolio Solutions and J.P. Morgan, all predicted long run stock returns to be below 8.0%. *Id.* at 33-34. Mr. Kaufman also cited additional supporting articles collected in his Appendix D. Mr. Kaufman then explained how Petitioner recognized that it's Pension and OPEBs and its NDT assume a "long-term" return on large capitalization equities of 9.0%. If an 9.0% forecasted return on large capitalization equities is appropriate to determine Petitioner's Pension/OPEB expenses, then it is also appropriate to help estimate its cost of equity (especially for models that rely on an estimate of market returns). *Id.* at 35.

(3) <u>IG Case-in-Chief and South Bend Case-in-Chief.</u>

**[NOTE - OUCC is not providing its own summary for sections 9-A-3(a) through 9-A-3(h) of the proposed order. OUCC adopts the Industrial Group's summary of witness Gorman's COST OF CAPITAL testimony.]**

(i) <u>South Bend Case-in-Chief.</u> South Bend Witness Cearley did not perform a DCF, CAPM or other COE analysis. He offered his opinion that I&M's return on equity should be lower than, and certainly no higher than, the ROE approved in its last rate case and suggested that I&M and its investors should tighten their belts by accepting a lower ROE. Cearley Direct, at 6-7.

(4) <u>I&M Rebuttal.</u> (NOTE - OUCC is not providing its own summary for this section of the proposed order with regards to I&M's rebuttal criticism of IG witness Gorman's COST OF CAPITAL testimony. OUCC adopts the Industrial Group's summary of I&M's rebuttal as it relates to witness Gorman's COST OF CAPITAL testimony.) Ms. Hawkins disagreed with Mr. Lorton's position that any benefits from the rate case will strengthen I&M from an "already strong" financial position. Hawkins Rebuttal, at 2. She contended the Company's credit metrics in 2011 benefited from the bonus depreciation from Federal tax stimulus. She added that in 2011, I&M's cash flow benefited by $141 million in deferred income taxes. She stated that credit ratings are forward looking analysis of a company's credit profile and cash flows from bonus depreciation will no longer be part of the cash flow and improving the financial credit metrics. She testified that I&M should be positioned with ongoing cash flows to support its operations as well as the expected capital projects for the environmental retrofits and the Cook Life Cycle Management project.

Ms. Hawkins agreed that I&M can partially manage the leverage through dividends and equity contributions, but emphasized that earnings and cash flow are just as critical. *Id.* at 3. She explained, in 2009, $125 million was contributed to I&M as part of the overall strategy to reduce the leverage. In Petitioner's Exhibit RVH-R1, Ms. Hawkins provided the dividends provided to the OUCC in discovery and the net income and payout ratios for those same years. She showed that at an average dividend payout ratio of 47.8%, I&M's dividend payout is lower than most regulated utilities with the majority of earnings retained and reinvested at the Company.

Ms. Hawkins explained that the credit rating agency inclusion of operating leases as total debt in the calculation of credit metrics shows a large differential between the GAAP capital structure and how I&M is viewed on a credit adjusted basis. *Id.* She added there are other obligations that are included in debt as well. She explained for the year end 2011, Moody's added $78 million of unfunded pension liabilities, $782 million for operating leases and $122 million for accounts receivable securitization to total debt as part of their credit analysis of I&M. She stated to the extent the unfunded pension obligations are reduced, it supports the overall credit position of the Company. *Id.*

Dr. Avera complained that Mr. Kaufman's and Mr. Gorman's analyses and their resulting recommendations are flawed and should be rejected. Dr. Avera explained that allowing I&M an opportunity to earn its allowed return is consistent with the financial integrity analysis presented by Mr. Lorton. Avera Rebuttal, at 6. He noted that were I&M to be downgraded by the rating agencies, it would be at the bottom of the investment grade category. He said Mr. Lorton is correct to characterize I&M's bond ratings as stable, but opined the rest of the story is that I&M's bond ratings are weak relative to its peers in the electric utility industry. *Id.* at 7. He testified that if the Commission were to order a surprisingly low ROE , investors could question whether I&M continues to have supportive regulation, a factor noted by the credit rating agencies as important to maintaining I&M's investment grade rating. Dr. Avera testified that if I&M is allowed a supportive ROE but continues to be unable to actually earn the allowed return, as Mr. Chodak claimed in his testimony, Indiana's reputation of supportive regulation could be also called into question by the investment community, at least as it applies to I&M. Dr. Avera complained that the credit metrics analysis presented by Mr. Lorton should not assuage fears of a bond rating downgrade for I&M because Mr. Lorton's analysis deals with I&M's historical financial performance ending on February 29, 2012 and ignores that going forward I&M will incur increased investment and expenses. *Id.* at 7.

Dr. Avera noted that the ROE in the Michigan settlement represents a reduction of allowed return from 10.35% to 10.2%. He explained that Mr. Kaufman proposes that the Indiana ROE be reduced from 10.5% to 9.2%. He emphasized that in recent years I&M has consistently fallen short of earning its allowed return. He said Mr. Kaufman recommends that the Commission not use the fair return on fair value increment to offset I&M's consistent earnings shortfall.

Dr. Avera noted that Mr. Cearley's comments fail to recognize the efficiency reflected in I&M's low rates and the ongoing efforts taken by I&M to control its costs and manage its system efficiently. He explained that the approach recommended by Mr. Cearley would harm, not benefit customers. He stated that investors have many choices competing for their capital. If I&M does not offer a return competitive with other enterprises of comparable risk, investors will migrate to the better opportunities. From an economic perspective, this is the genius of the U.S. Supreme Court decisions in the *Hope* and *Bluefield* cases discussed by Mr. Lorton.

Dr. Avera asserted that Mr. Kaufman and Mr. Gorman's analysis recognize that I&M has relatively greater investment risk than other utilities. *Id.* at 10-11. He stated that S&P ranks I&M as considerably higher in risk compared to other utilities. *Id.* at 11-12. He noted that his direct testimony discussed the fundamental risk exposures that drive investors to regard I&M as a relatively risky utility, including its exposure to nuclear power and large capital needs. The end result is that I&M must offer investors a higher return than its peers to compete for capital. He explained that if the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. He added that for existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. He said in this situation the government is effectively taking the value of investors' capital without adequate compensation. *Id.* at 12.

(a) Expected Earnings Analysis. Dr. Avera argued Mr. Kaufman's and Mr. Gorman's position that the comparable earnings analysis Dr. Avera used is not a reasonable method to estimate a fair ROE for I&M. He asserted that the traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. He explained that while the traditional comparable earnings test is implemented using historical data taken from the accounting records, more recently it is implemented using projections of returns on book investment, such as those published by Value Line. He stated that because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison. Dr. Avera noted that in a previous electric rate case Mr. Kaufman presented both a survey of authorized returns from *Public Utilities Fortnightly* to support the reasonableness of his independent study and a comparison of actual returns from CA Turner Report, which is directly analogous to Dr. Avera's expected earnings approach, but using historical earned return on equity instead of Value Line expected return.

Dr. Avera conducted an expected earnings analyses on the proxy groups used by Mr. Kaufman and Mr. Gorman. Those results (presented on Petitioner's Exhibits WEA-R1 and WEA-R2) show that these companies are expected to earn more than these witnesses are proposing to allow I&M. Similarly, in Petitioner's Exhibits WEA-R3 and WEA-R4, Dr. Avera presented the authorized returns for both Mr. Kaufman and Mr. Gorman's proxy groups, and again the results presented prove to be higher than the ROEs Mr. Kaufman and Mr. Gorman are recommending for I&M in Indiana. *Id.* at 14.

While he agreed that market-based models are certainly important tools in estimating investors' required rate of return, Dr. Avera testified that this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages. He said a very simple, conceptual principle is that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. He contended if I&M is only allowed the opportunity to earn a 9.5% return on the book value of its equity investment, as recommended by Mr. Gorman, while other electric utilities are expected to earn an average of 10.5%, the implications are clear – I&M's investors will be denied the ability to earn their opportunity cost. Dr. Avera added that regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, Dr. Avera argued the (3 – 5 year) expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. He said this opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

It was put forth by Dr. Avera that the comparable or expected earnings approach has been recognized as a valid ROE benchmark in Indiana and elsewhere. *Id.* at 15, 17-20. He said, in fact the *Practitioner's Guide* prepared for the Society of Utility and Regulatory Analysts (the organization that granted Mr. Kaufman the designation Certified Rate of Return Analyst) labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal", particularly when compared to the DCF and CAPM methods. *Id.* at 15-16. He added that this *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases, as well as sound regulatory economics. *Id.*

(b) Comparable Risk Proxy Groups. Dr. Avera argued while Mr. Kaufman and Mr. Gorman recommended returns near the top of their results from financial models, they did not look at the *end result* in terms of what other utilities are allowed to earn and are expected to be able to actually earn. Dr. Avera put forth that Mr. Kaufman's recommended ROE for I&M would fall short of what other utilities are expected to actually earn. *Id.* at 17. Dr. Avera asserted that assuming that I&M was expected to actually earn Mr. Kaufman's 9.2% recommended ROE, such a return would not produce an *end result* that would enable I&M to effectively compete with other utilities to attract capital because it falls far below the 10.0% return expected for Mr. Kaufman's proxy group. Dr. Avera argued that in light of Mr. Kaufman's own testimony that I&M's risks warrant a higher return; this 10.0% benchmark represents a floor on a reasonable ROE for the Company.

Dr. Avera also asserted the expected earnings for Mr. Gorman's proxy group (Petitioner's Exhibit WEA-R2) average 10.2%. Dr. Avera explained that because Mr. Gorman's recommended ROE falls below what the utilities in Mr. Gorman's own proxy group are expected to earn, it violates the opportunity cost standard underlying a fair ROE and is insufficient to allow I&M an opportunity to attract capital on reasonable terms. *Id.* at 17.

According to Dr. Avera, Mr. Kaufman and Mr. Gorman offered no meaningful criticisms of his use of a Non-Utility Proxy Group. Dr. Avera stated that Mr. Kaufman and Mr. Gorman dismiss out of hand his analysis of the cost of equity for non-utility firms based on their premise that these companies have higher risk. He complained the implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with investor behavior, and the *Bluefield* and *Hope* decisions. Dr. Avera stated that the idea that investors evaluate utilities against the returns available from other investment alternatives –

including the low-risk companies in his Non-Utility Proxy Group – is a fundamental cornerstone of modern financial theory.

He said, aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless, and common sense supports the notion that utilities must offer a return that can compete with other risk comparable alternatives, or capital will simply go elsewhere. He stated, in fact, returns in the competitive sector of the economy form the underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. Dr. Avera acknowledged that utilities in Indiana are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market.

Dr. Avera explained that his Non-Utility Proxy Group is comprised of 53 of the best-known and most stable corporations in America and has risk measures that are comparable to, or less than the proxy group of utilities referenced in his analyses. He asserted that while these companies are not regulated they do not bear the burdens of losing control over their prices, undertaking the obligation to serve, and having to invest in infrastructure even in unfavorable market conditions. I&M cannot relocate its service territory to an area with a more attractive business climate or higher prospects for economic growth, or abandon customers when turmoil roils energy or capital markets. Investors are aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to provide service and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed rate of return on invested capital. He said the observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. *Id.* at 82.

Dr. Avera noted that neither Mr. Kaufman nor Mr. Gorman presented objective evidence to support their contention that his Non-Utility Proxy Group is riskier than I&M or Dr. Avera's proxy group of electric utilities. *Id.* Dr. Avera presented an analysis that he thought refuted Mr. Kaufman's and Mr. Gorman's claim, showing that the average corporate credit rating for the Non-Utility Proxy Group of "A" is higher than the "BBB" average for the Utility Proxy Group and I&M. *Id.* at 83. Dr. Avera also showed that all of the firms in his Non-Utility Proxy Group have a Safety Rank of "1", which classifies them among the least risky stocks covered by Value Line. Meanwhile, the Safety Rank corresponding to the firms in his Utility Proxy Group and I&M is "3." *Id.* at 84. Similarly, Dr. Avera showed the average beta value of 0.71 for the Non-Utility Proxy Group is less that the 0.74 average for the Utility Proxy Group and essentially identical to the value corresponding to I&M. Dr. Avera concluded that this review of objective indicators of investment risk supposedly demonstrates that, if anything, the Non-Utility Proxy Group could be considered somewhat less risky in the minds of investors than I&M or the common stocks of the proxy utilities. *Id.*

Dr. Avera explained why he believed the fact that utilities are regulated does not somehow invalidate the comparison of objective risk indicators. While he did not disagree that utilities operate under a regulatory regime that differs from firms in the competitive sector, he said any risk-reducing benefit of regulation (including the trackers cited by Mr. Kaufman), is already incorporated in the overall indicators of investment risk presented above. Dr. Avera explained that the impact of regulation on a utility's investment risks is one of the key elements considered by credit rating agencies and investment advisory services, such as S&P and Value Line, when establishing corporate credit ratings and other risk measures. He said, as a result, the impact of regulatory protections is already reflected in his risk analysis. Meanwhile, the beta values supported by modern financial theory are premised on stock price volatility relative to the market as a whole, and are not dependent on an assessment of firm-specific considerations. He said, as a result, the impact of regulatory differences – including trackers – on investment risk is accounted for in the published risk indicators relied on by investors and cited in his direct testimony. *Id.* at 84-85.

Dr. Avera theorized that unregulated companies have the opportunity to change prices whenever they wish, including in response to an increase in production costs. Similarly, unregulated companies can respond to higher costs by abandoning a product or geographic area if it is unprofitable. Dr. Avera alleged that unregulated companies do not risk disallowances by regulators, only the discipline of the marketplace. He thought that in general unregulated companies are more risky than electric utilities for a variety of reasons. But the Non-Utility Proxy Group that he used should not be dismissed based on generic arguments as Mr. Kaufman has done (at 7) because Dr. Avera selected a group of the least risky of all non-utilities followed by Value Line based on the same objective risk measures used to select the Utility Proxy Group.

(c) Flotation Costs. Dr. Avera put forth there is no justification for ignoring flotation costs in the end result test. He complained that Mr. Kaufman and Mr. Gorman present a "catch 22" to prevent regulatory recovery of these costs. He thinks that I&M has been and will continue to invest massive amounts of equity capital to serve the public and the earnings base of this equity is permanently reduced by the amount of past flotation costs. He alleged that without a flotation adjustment, these legitimate costs of providing utility service will be excluded for ratemaking purposes and will further undercut I&M's ability to earn its authorized ROE.

(d) Change in Bond Yields Following Date of Dr. Avera Analysis. Dr. Avera argued that the drop in treasury bond yields does not translate directly into lower equity costs for utilities like I&M. He said that investors have been buffeted by dramatic developments in international capital markets that have continued in the months since he filed his direct testimony, including the continuing flare ups in the European debt crisis and concerns about the health of large banks around the world, including those in the U.S. Dr. Avera explained that as a result, investors have fled out of risk assets into less risky assets like U.S. Treasury bonds. He asserted that as Treasury yields push deeper into historical lows driven by investors' "flight to safety," stock markets have tumbled. He added that because I&M is on the more risky end of the utility spectrum, it is not completely clear that falling interest rates on U.S. Treasuries translate into significantly lower costs of equity for I&M. He observed that if such a simple relationship did indeed exist, cost of equity experts would add little value beyond regurgitating Treasury yields.

(e) Mr. Kaufman's DCF. Dr. Avera argued that Mr. Kaufman's DCF analysis is flawed because it uses growth rates Mr. Kaufman regards as reasonable rather than those used by investors. Dr. Avera put forth that growth rates are an input, not the output of the DCF model. He complained Mr. Kaufman mixes historical growth rates and projected growth rates of earnings per share, dividends, and book value per share without regard to what investors may be actually expecting for growth today when they put their money down to buy a stock. *Id.* at 27. Dr. Avera opined that in the case of utilities, growth rates in dividends per share ("DPS") are not likely to provide a meaningful guide to investors' current growth expectations because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry. Thus, according to Dr. Avera past DPS growth measures are not representative of long-term expectations for the utility industry. Dr. Avera stated that as payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from DPS to earnings as a measure of long-term growth. He stated that future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. He said the fact that investment advisory services focus primarily on growth in EPS indicates that the investment community regards this as a superior indicator of future long-term growth. He added that to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts. He alleged that Mr. Kaufman's analysis reflects a downward bias because he relies on historical dividends to predict dividend growth. *Id.* at 28-29. Dr. Avera theorized that the most reliable way to estimate the growth rate investors are actually using when they purchase a particular stock at a particular time is to reference publications used by investors and research on investor behavior as Dr. Avera did in his analysis. *Id.* at 29. He said that Mr. Gorman's testimony corroborates this view. *Id.*

Dr. Avera agreed Mr. Kaufman repeatedly used a growth measure in the model based on Mr. Kaufman's view of past Commission orders, particularly those in water utility rate cases. Dr. Avera argued that past Commission decisions regarding particular growth measures for particular types of utilities should not lock in the measures used to estimate growth expectations now and in the future. *Id.* at 30-31.

Dr. Avera identified studies that he claimed contradicted Mr. Kaufman's position that analysts' projections are optimistic, but pointed out the key issue is that, regardless of their accuracy, investors rely on these projections. *Id.* He explained that the fact that analysts' EPS projections may deviate from actual results does not hamper their use in applying the DCF model as he argues Mr. Kaufman contends. He testified that investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. He said investors can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock. Dr. Avera added that securities prices are constantly adjusting to reflect investors' assessment of available information.

Dr. Avera asserted that while the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices. He said any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. *Id.* at 32-35. Dr. Avera noted that Value Like is a well-recognized source in the investment and regulatory communities that does not sell or underwrite securities. He noted that Value Line was among the providers of "independent research" that benefited from the Global Settlement cited by Mr. Kaufman in his Appendix A. He added that the studies cited in Mr. Kaufman's appendix predate the changes in analyst compensation and reporting ordered as a result of some of the "tech bubble" excesses. Dr. Avera noted that on Schedule ERK-2, Page 3 of 4, the average Value Line

Forecasted earnings per share growth is 6.17% versus 4.87% for Yahoo.com and Zacks that survey analysts in the capital markets. He added that considering that the consensus analyst estimates are actually lower than those published by Value Line, which is immune to any potential conflicts associated with investment banking operations, this undercuts Mr. Kaufman's unsupported allegations of bias. *Id.* at 35.

Dr. Avera said that Mr. Kaufman eliminated growth rates less than 1% but kept low growth rates based on the premise that they are not ignored by investors. Dr. Avera asserted that the proper inquiry is whether a growth rate produces a DCF estimate that identifies it as an outlier that should not be used in estimating investors' required returns. This is the approach he used, and the approach that he alleged FERC has taken when it adopted the constant growth DCF based on earnings growth projections and sustainable growth. *Id.* at 36. Dr. Avera said that when Mr. Kaufman's DCF is corrected to eliminate illogical, low-end values, as well as high-end outliers, consistent with the FERC approach, the implied COE ranges from 9.6% to 11.6% with the midpoint being 10.6% and an average of 10.4%. Dr. Avera's Exhibit WEA-R6 put forth that the average cost of equity implied by Mr. Kaufman's corrected DCF analysis based on analysts' growth projections was 9.9%.

Dr. Avera argued that there is no basis to assume that Mr. Kaufman's two-stage DCF model reflects investor expectations. Dr. Avera claimed that the only relevant growth rate is the growth rate used by investors, whether it is "intermediate" or not. He contended that investors do not have clarity to see far into the future, and noted that Mr. Kaufman presents no evidence that investors evaluate the future based on the assumptions and data sources that were required to apply Mr. Kaufman's two-stage model. Dr. Avera claimed, on the contrary, in the financial media one observes many references to 3-5 year earnings growth forecasts for individual companies and very few references to very long-term GDP forecasts. He said long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms.

(f) Mr. Kaufman's CAPM. Dr. Avera asserted that Mr. Kaufman's CAPM results are flawed and should be ignored because they are based almost exclusively on *historical* rates of return, not current projections and thus fall short of investors' current required rate of return. *Id.* at 39. Dr. Avera argued that Mr. Kaufman did not attempt to develop a market risk premium using current capital market information. Rather, his Appendix C presented the results of various studies and surveys conducted almost exclusively in the past and long before recent dislocation in financial markets and the onset of recession. *Id.* at 40.

Dr. Avera argued that the backward-looking approaches used by Mr. Kaufman incorrectly assume that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some historical average. Dr. Avera reasoned that the incongruity between investors' current expectations and requirements and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. He said as a result, there is every indication that the historical CAPM approach used by Mr. Kaufman fails to fully reflect the risk perceptions of real-world investors in today's capital markets, and this in turn violates the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk. *Id.* at 41.

Dr. Avera put forth that surveys of corporate executives or economists, or building blocks based on academic research, are not equivalent to investors' required returns in the coming period. *Id.* at 43. Since the benchmark for a fair ROE requires that the utility be able to compete for capital in the current capital market, the relevant inquiry is to determine the return that real world investors in today's markets require from I&M in order to compete for capital with other comparable risk alternatives. *Id*

Dr. Avera also argued that the risk premium that Mr. Kaufman derived from Ibbotson Associates' Data did not comport with what this publication reports. He noted that Ibbotson Associates (now *Morningstar*) computes the equity risk premium by subtracting the arithmetic mean income return (not the total return) on long-term Treasury bonds from the arithmetic average return on common stocks. In other words, *Morningstar* concluded that using only the *income component* of the long-term government bond return provides a more reliable estimate of the expected risk premium because investors do not anticipate capital losses for a risk-free security. Mr. Kaufman, however, calculated his equity risk premium using the *total* return for *Morningstar's* long-term government bond series. As a result, the equity risk premium Mr. Kaufman presents falls below what Morningstar reports and the resulting CAPM cost of equity estimate, according to Dr. Avera, is understated. *Id.* at 44. Dr. Avera stated that the most recent edition of Mr. Kaufman's source of historical realized rate of return data calculates the long-horizon equity risk premium by subtracting the arithmetic mean average income return on long-term Treasury bonds from the arithmetic mean average return on the S&P 500, would result in an equity risk premium of 6.62% , versus the 5.7% value reported by Mr. Kaufman. *Id.* at 44-45.

Dr. Avera also disagreed with Mr. Kaufman's view that geometric means provide a better measure of expected returns when applying Mr. Kaufman's historical CAPM. He contended that while both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be in each period to achieve the realized change in value over time. Dr. Avera asserted in estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods.

He opined the issue is not whether both measures can be useful; it is which one best fits the use for a forward-looking CAPM in this case. Dr. Avera argued the Commission is not setting a constant return that I&M is guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, I&M's yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year. Dr. Avera claimed that Mr. Kaufman's reference to geometric average rates of return provides yet another element of downward bias in Mr. Kaufman's analysis. *Id.* at 47-48.

Mr. Kaufman testified that Dr. Avera's approach to the CAPM risk premium should be rejected. Mr. Kaufman explained that in prior Commission orders it has given weight to both the geometric mean and arithmetic mean to estimate the risk premium in the CAPM. However, Dr. Avera argued this method fails to recognize that Dr. Avera's use of a forward-looking estimate of the market return in the CAPM analysis renders debate over the geometric or arithmetic mean moot. *Id.* at 47-48.

(g) CAPM Size Adjustment. Dr. Avera noted that Morningstar (a source used by Mr. Kaufman), recognizes the relationship between firm size and return. *Id.* at 48-49. Dr Avera explained that because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect. *Id.* at 49. He stated that according to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. Dr. Avera asserted the need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. He stated that to account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. Accordingly, Dr. Avera's CAPM analyses for Mr. Kaufman's proxy group incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization. *Id.*

Dr. Avera added that he is not proposing to apply a general size risk premium in arriving at a proposed fair ROE for I&M as he asserts Mr. Kaufman implies. Rather, Dr. Avera's adjustment allegedly corrects for an observed inability of the CAPM to fully reflect the impact of size distinctions by market capitalization that the beta value does not otherwise capture, but which is acknowledged by empirical research. *Id.* at 49-50.

Dr. Avera distinguished his adjustment from the Commission decisions and articles cited by Mr. Kaufman. He argued that the adjustment made in the sources cited by Mr. Kaufman was meant to reflect a purported risk difference between the individual water utility at issue, and the overall ROE indicated by the underlying analyses. Dr, Avera added that this is not what he is proposing in this case. Dr. Avera's consideration of the impact of firm size does not adjust for I&M's size relative to the proxy group; nor is it applied to the results of the DCF, risk premium, or expected earnings approaches. Rather, it is tied to the CAPM because Morningstar's empirical research indicates that beta does not capture an increment of risk related to firm size. Dr. Avera noted that the highlighted quotation from the article on business valuation cited by Mr. Kaufman (at 51) does not have relevance to a fair ROE for I&M in this case because I&M is not "a private water utility," its position within the industry is not one of "very low risk," and the Company's history demonstrates that it does not have any "near guarantee" of earning a fair ROE. *Id.* at 50.

Dr. Avera stated there are any number of specific factors that distinguish a utility's risks from other firms in the non-regulated sector, just as there are distinctions between the circumstances faced by airlines and drug manufacturers. But under the assumptions of modern capital market theory on which the CAPM rests, these considerations are reduced to a single risk measure – beta – which captures stock price volatility relative to the market. He said that utilities are included in the companies used by *Morningstar* to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. All else being equal, it is accepted that smaller firms are more risky than their larger counterparts, due in part to their smaller scale, relative lack of diversification and lower financial resiliency. Dr. Avera stated that in the case of a smaller utility, its earnings are principally dependent on the economic, social, regulatory, and other factors affecting a more limited constituency. This can result in significant exposure, especially where key employers or industries dominate the economy. *Id.* Dr. Avera said that larger electric utilities generally enjoy improved exposure to financial markets, which enhances their ability to raise additional capital relative to smaller utilities. As a result, they are better prepared to withstand adverse events and possess greater financial flexibility to respond or adapt to changing market conditions, such as those that currently confront the electric utility industry. Dr. Avera opined that in contrast to Mr. Kaufman's conclusions (at 50-51), the size effect has also been documented in the utility industry. *Id.* at 51-52. He asserted that a study reported in *Public Utilities Fortnightly* also concluded that a publicly traded utility with a market capitalization of $1.0 billion would require a small company premium of approximately 130 basis points above the rate of return for larger firms. *Id.*

Dr. Avera alleged that application of the forward-looking CAPM approach resulted in an unadjusted ROE of 10.7% for the firms in Mr. Kaufman's proxy group, or 11.5% after adjusting for the impact of firm size. Dr. Avera contended that there is consensus that interest rates will increase materially as the economy strengthens. *Id.* at 52. He put forth that incorporating a forecasted Treasury bond yield for 2012-2016 implied an unadjusted cost of equity of approximately 11.0% for the utilities in Mr. Kaufman's proxy group, or 11.8% after accounting for firm size.

Dr. Avera argued that Mr. Kaufman's criticism of Dr. Avera's forward-looking market return is not consistent with Mr. Kaufman's own testimony in one prior electric rate case where 15 years ago he applied the CAPM approach using a forward-looking DCF model in a similar fashion as Dr. Avera did here. *Id.* at 52-53.

(h) Pension And Similar Return Assumptions Are Not Comparable. Dr. Avera complained that the forecasted pension return referenced by Mr. Kaufman is not an appropriate benchmark for I&M's allowed ROE. First, the long-run projected return for equity investments assumed for pension portfolios is generally a geometric mean return indicative of compound returns earned over a long horizon. He asserted this is not equivalent to the specific benchmark for investors' forward-looking required rate of return represented by the requested ROE, which is in the nature of an arithmetic mean. When returns are variable, the geometric mean is always less than the arithmetic mean. Second, the pension projection applies to equity investments made in the pension portfolio, which are selected by the pension managers from the many available choices in the equity markets. Dr. Avera asserted that pension investments must conform to the requirements of prudence, which includes the "three elements of care, skill, and caution." The requirement for prudence extends to the projections of pension portfolio returns. He said the projection of pension returns falls under the scrutiny of the U. S. Department of Labor and the U. S. Securities and Exchange Commission, as well as the prudence requirements of the ERISA. In light of this guidance and oversight, the portfolio return projection represents a compound return that the fiduciaries are confident that they can meet or exceed over long periods of time. *Id.* at 54.

Dr. Avera said that the utility's allowed ROE is specific to the risks and circumstances of I&M's utility operations and a set of comparable risk companies. He stated that in order to meet the comparable earnings, financial integrity, and capital attraction standards of *Hope* and *Bluefield* the allowed ROE must be measured by reference to investors' expectations and requirements for comparable risk companies. He argued in contrast, the objective of pension projections is to formulate future expectations for the equity investments in the pension portfolio based on an informed interpretation of historical experience and in light of accepted standards of prudence, and there can be key differences in the data sets and approaches used to derive pension plan projections. Dr. Avera noted the California Public Utilities Commission concluded, "Pension return assumptions are not comparable to the ROE used in utility ratemaking." *Id.* at 55.

(i) Mr. Gorman's DCF. (NOTE - OUCC is not providing its own summary for this section of the proposed order with regards to I&M's rebuttal criticism of IG witness Gorman's DCF. OUCC adopts the Industrial Group's summary of I&M's rebuttal as it relates to witness Gorman's DCF.)

(j) Mr. Gorman's Risk Premium. (NOTE - OUCC is not providing its own summary for this section of the proposed order with regards to I&M's rebuttal criticism of IG witness Gorman's Risk Premium. OUCC adopts the Industrial Group's summary of I&M's rebuttal as it relates to witness Gorman's Risk Premium.)

(k) Mr. Gorman's CAPM. (NOTE - OUCC is not providing its own summary for this section of the proposed order with regards to I&M's rebuttal criticism of IG witness Gorman's CAPM. OUCC adopts the Industrial Group's summary of I&M's rebuttal as it relates to witness Gorman's CAPM.)

(l) Impact of Rate Adjustment Mechanisms. Dr. Avera alleged that there is no reason to adjust I&M's ROE downward based on the rate adjustment or accounting mechanisms. *Id.* at 85. He said that his view is consistent with Mr. Kaufman's testimony. Dr. Avera explained that trackers do not change the fundamental regulatory requirement that a utility have a reasonable opportunity to recover its reasonable and necessary expenses plus a fair rate of return on investment. He theorized that trackers do not eliminate the main regulatory risk that concerns investors: that an expenditure or investment will be disallowed because it is deemed unreasonable, unnecessary, or imprudent. He stated that when recovery is in base rates, the utility may over or under recover its expenses based on how actual revenues and costs behave between rate cases. If an expense or investment is moved to a tracker, the utility normally forgoes the upside possibility of over-recovery but benefits from avoiding the down-side of under-recovery. He noted that while I&M has a number of trackers but so do the utilities in the Utility Proxy Group. Dr. Avera testified that the major storm reserve treatment does not alter the fundamental principle that I&M should be allowed to recover its reasonable and necessary expenses. The exposure to disallowance for storm restoration expenses found unnecessary, unreasonable, or imprudent remains. Moreover, provisions to recover major storm restoration expenses are common for electric utilities in the proxy group. *Id.* at 86. Dr. Avera alleged that the ability of a utility to recover costs via tracking mechanism does not mean that unregulated companies are not comparable in risk because unregulated companies have the opportunity to change prices whenever they wish, including in response to an increase in production costs and can abandon a product or geographic area if it is unprofitable. He said unregulated companies do not risk disallowances by regulators, only the discipline of the marketplace. *Id.* at 87.

Finally, Dr. Avera noted evidence documenting that OSS margins are volatile based on the interaction of market forces in the electricity market. He stated if a substantial sum like $33 million (Blakley) or $37.5 million (Dauphinais) is embedded in basic rates, it is a significant portion of I&M's authorized net operating income. Dr. Avera testified if market conditions turn out so that OSS margins fall far below the amount included in basic rates, I&M suffers a significant earnings shortfall. He argued given the Company's relatively weak bond rating and history of under-earnings, the inclusion of an offset to revenue requirements due to OSS margins could damage I&M's credit ratings and financial integrity, contrary to the *end result* test discussed above. He explained that customers have an important stake in I&M's credit ratings and financial integrity, so damage to I&M harms customers in the long-run. Dr. Avera stated that the regulatory objective is to incent I&M to seek market opportunities to achieve maximum OSS margins and limiting the amount of sharing undermines this incentive. *Id.* at 88.

(5) Commission Discussion and Findings. (NOTE – OUCC's proposed order does not include specific summaries of IG Witness Gorman's testimony on any Cost of Capital issues. OUCC adopts IG's statements addressing Mr. Gorman's Cost of Capital issues for inclusion in this portion of the Proposed Order).

Proxy Groups

All witnesses relied on a proxy group or groups of companies to estimate Petitioner's cost of equity. Determining an appropriate proxy group is typically a balancing act between selecting a group of representative companies and using a proxy group that has a sufficiently large number of members so that no single company exerts undue influence on the estimated cost of equity.

Electric proxy group

Both Mr. Kaufman and Mr. Gorman asserted several of the companies used by Dr. Avera in his electric utility proxy group did not adequately represent Petitioner's activities. For example, Mr. Kaufman excluded ITC Holdings Corp. (pure transmission company; equity ratio well below both Petitioner and group) as well as several other companies deriving less than 50% of their revenues from electric operations. In this cause, the Commission will authorize a cost of equity for Petitioner's regulated electric operations. Requiring utility proxy members to share substantial similarity among basic characteristics such as the percentage of revenues is reasonable. Listed as an "electric company" by Value Line, ITC Holdings derives none of its revenues from state regulated electric operations. While the Commission understands that proxy group creation requires that experts utilize some discretion, Dr. Avera's group contains several companies inappropriate for inclusion. Mr. Kaufman's 18-member electric utility proxy group is sufficiently large and better represents both risk characteristics and operations of Petitioner.

Non-utility proxy group

By definition a non-utility proxy group will not mimic Petitioner's operations. The Commission may consider a non-utility proxy group when 1) required by the individual circumstances and 2) the group's risk is similar to Petitioner. Dr. Avera includes a non-utility proxy group, but there is no evidence of special circumstances that would merit its use. To the contrary, there are several companies in the Electric Proxy Group with risk and operations similar to Petitioner. Regarding risk similarities, Mr. Kaufman is correct that Dr. Avera did not screen his non-utility proxy group for equity ratio or dividend yield, two key criteria. Three of Dr. Avera's four highest cost of equity estimates are results from his non-utility DCF analysis, exceeding their utility counterpart by more than 200 basis points. While mindful of the pitfalls created if non-utility proxy results are eliminated simply because they are not utilities, a spread this large indicates risk characteristics substantially dissimilar from both the utility proxy group and Petitioner. Petitioner's cost of equity can and will be estimated without resorting to a non-utility proxy group.

DCF Model

Three witnesses presented a DCF model, each with different mechanics. The key difference between the witnesses was their estimated growth rate (g). In three of his models Dr. Avera relied exclusively on 3-5 year forecasted earnings per share, while Mr. Kaufman relied on both historical and forecasted growth rates in EPS, DPS and BVPS in his single stage DCF model.

Dr. Avera's models rely on 3-5 year forecasted earnings per share growth because he claims these are the growth rates actually used by investors. We agree with Mr. Kaufman that investors temper 3-5 year earnings per share growth estimates by considering other estimates and by discounting analyst recommendations. We reject the notion that investors blindly disregard all other information. This Commission has consistently relied on multiple estimators of growth to estimate cost of equity in a DCF model. We continue to believe investors consider more evidence rather than less. Exclusive reliance on unadjusted 3-5 year EPS growth rates is a decision fraught with problems:

> Forecasted EPS estimates are not long term (perpetual) estimates. The so called "long-term" estimates of EPS provided by companies that make such estimates are typically for only three to five years. Three to five year estimates (by themselves) do not necessarily represent a reasonable long term estimate. Moreover, analyst forecasts of EPS tend to be optimistic, overstate long term growth and should not be used in isolation.
>
> Kaufman Direct, at 37.

In our recent Cause No. 43874, Utility Center, Order dated April 13, 2011, this Commission found (page 21) using unadjusted analyst recommendations increases the probability of producing overstated DCF results. As Mr. Kaufman correctly noted, Dr. Avera did not make a comparable discount when he relied on analyst recommendations. Kaufman Direct, at

39-40. We will give his DCF results less weight than Mr. Kaufman's, which is more consistent with past Commission orders and our continuing perspective.

Mr. Kaufman also explained on page 39 of his testimony that investors discount analyst recommendations. He quoted from an article titled, "Do Analyst Conflicts Matter? Evidence from Stock Recommendations" by Anup Agrawal and Mark Chen (Journal of Law and Economics, 2008, V 51). The article explained that: "Overall, our empirical findings suggest that while analysts do respond to IN [investment bank] and brokerage conflicts by inflating their stock recommendations, the markets discount these recommendations after taking analysts' conflicts into account."

In rebuttal Dr. Avera cited several articles he claimed refuted Mr. Kaufman's assertions that analyst forecasts are optimistic. Having reviewed the articles, we find them unpersuasive. These articles appear to reference quarterly earnings forecasts and not 3-5 year forecasts.

Dr. Avera criticized both Mr. Kaufman's use of a 2-stage DCF model and his inputs, arguing that 2-stage DCF models are appropriate only in unusual or extreme circumstances. Mr. Kaufman explained because the DCF model requires a long term/ perpetual growth, a 2-stage DCF model provides an opportunity to include current 3-5 year growth forecasts while recognizing the intermediate term nature of these forecasts. Even when used by investors, analyst growth forecasts are not long term forecasts that can be blindly incorporated into a single stage DCF model. This is especially true when these intermediate term forecasts exceed the long run growth rate of the US economy. As Mr. Kaufman and his supporting articles (Kaufman Direct, Appendixes A & E) make clear, a company's sustainable growth rate for DCF purposes cannot exceed the growth rate of the economy. These texts also support Mr. Kaufman's use of long term GDP for the 2$^{nd}$ stage in his 2-stage DCF model.

CAPM

Dr. Avera, Mr. Kaufman and Mr. Gorman all used the CAPM. Issues creating the greatest conflict were 1) market risk premium, 2) projected bond yields and 3) size premium.

Petitioner was highly critical of Mr. Kaufman's use of both a geometric and arithmetic mean to estimate his CAPM risk premium. There are well-reasoned experts on both sides of this issue. This Commission has historically found both the arithmetic and geometric mean risk premiums provide meaningful insight to estimate a historical risk premium. In particular, the geometric mean provides a valuable balance, as highlighted in the Damodaran article Equity Risk Premiums (ERP): Determinants, Estimations and Implications – The 2012 Edition (p. 25):

> There are, however, strong arguments that can be made for the use of geometric averages. First empirical studies seem to indicate that returns on stocks are negatively correlated[47] over time. Consequently, the arithmetic average return is likely to over state the premium.
>
> Kaufman Direct, at 8

For at least twenty years this Commission has given substantial weight to both the arithmetic and geometric mean calculation to estimate a historical risk premium in a CAPM analysis. We continue to do so today. After two decades of consistent orders on the topic, we consider this issue resolved.

As part of estimating his market risk premium, Dr. Avera ultimately proposed using a total market return of 13.5%. Avera Rebuttal WEA-R7; see also Avera Direct WEA-6 (13.2%). Mr. Kaufman testified that Dr. Avera's estimated market return is unreasonable, exceeding by (140 bp) the arithmetic and (by 340 bp) geometric mean historical returns. Because Dr. Avera's CAPM uses a DCF model to estimate market return, the DCF estimated growth rate is held to same standard as when the DCF model is used to estimate cost of equity. Thus, all the shortcomings we recognize above in discussing Dr. Avera's DCF (exclusive reliance on intermediate term earnings growth, for example) equally apply to the DCF-powered growth estimate used to derive his CAPM estimated market return.

Mr. Kaufman testified that a 9.0% estimated market return was more reasonable. He noted that Petitioner assumes that level of return for investments it makes in its OPEB/Pension and its nuclear decommissioning trust. Kaufman Direct, at Attachments ERK-7 and ERK-8. I&M invests funds in a broad index of market equities. Their estimated return is reflective of the anticipated market return. As such, it is only reasonable for us to consider, particularly when reviewing models based on market returns.

Despite testimony from its President and COO that I&M is "continuing to face a weak economy and a relatively flat growth rate" (Chodak Direct, at 33:6-8), I&M proposes to base its cost of equity determination on a model expecting a market return that exceeds long term historical returns. Today, the United States and the State of Indiana still suffer from the largest economic down turn since the Great Depression. Reasonable market models should reflect this circumstance. Petitioner's proposed 10.9% estimated growth rate (Avera Direct, at WEA 6, page 1), drastically exceeds the growth of the US economy, highlighting the shortcomings created by relying on a single growth estimate. Based on all of the above, we conclude Dr. Avera's CAPM results are most probably overstated.

In past cases the Commission has questioned the reliability of models that move in the opposite direction of capital costs. Mr. Kaufman (Direct, at 47) demonstrated mathematically that Dr. Avera's CAPM is completely insensitive to changes in interest rates when beta is 1.0 and actually declines in response to increases in interest rates when beta exceeds 1.0. As such, this particular version of the CAPM adds little, if any, aid in our determination of an appropriate cost of equity.

Dr. Avera also performed a separate CAPM, this one based on forecasted interest rates. A forecasted increase to interest rates is by definition a forecasted decline to bond prices. Current investors would be aware of any forecasted decline in interests when they make a current purchase. Because logical investors will not buy a long term 30-year bond and simultaneously anticipate a market loss, the current purchase will necessarily reflect any anticipated decline in interest rates. This Commission believes that the best forecast of forecasted interest rates is how investors are voting with current dollars. Forecasted interest rates do not provide sufficient insight into improving our cost of equity determination and we find it inappropriate to use them in a CAPM analysis.

Dr. Avera also argues that current low interest rates do not reflect current capital costs and should be disregarded as we estimate Petitioner's cost of equity. Dr. Avera argues that the flight to safety has artificially depressed US Treasury bond returns. While a flight to safety may explain low short-to-intermediate term bond yields, investors willingly locking their money up for 30 years at interest rates in the low 3.0% range are not temporary flights to safety. Second we cannot accept Dr. Avera's invitation to ignore the more than 100 basis point drop in utility bonds yields over the past twelve months as shown in Attachment ERK 2. Declining utility bond yields reflect declining utility capital costs and contradict Dr. Avera's assertion that declining interest rates should be ignored.

Size Adjustment

Dr. Avera proposed an 81-basis point size adjustment. Avera Direct, at WEA-6. Like many witnesses in past cases, Dr. Avera relies on Ibbotson's equity size premium adjustment data. Mr. Kaufman (Direct, at 50-51) argued directly applying Ibbotson's adjustment to regulated utilities was inappropriate. Regulation decreases the risks (such as bankruptcy, for example) faced by Petitioner and the companies in Dr. Avera's electric utility proxy group relative to similarly-sized-but-unregulated companies. The Commission rejected a similar adjustment in Indiana American Water, Cause No. 43680:

> The Commission rejects Petitioner's equity size premium adjustment because it cannot be directly applied to regulated water utilities. Regulated water utilities do not experience the same risks as other small companies. Therefore a size adjustment is simply inapplicable and inappropriate for Indiana American.
>
> Order at 47.

While Petitioner is not a water utility the same theory holds for a large regulated electric utility such as I&M with over $4.0 billion in capital and owned by an even larger holding company (AEP).

Risk Premium and Expected Earnings models

Dr. Avera also "considered" (Petitioner's Proposed Order at 44) a Risk Premium model and an Expected Earnings model not used by either Mr. Kaufman or Mr. Gorman. Mr. Kaufman raised two significant concerns with the Risk Premium model: 1) it inappropriately utilized commission-authorized costs of equity to estimate a required rate of return, and 2) the model's expected return was unreasonable.

Regarding commission-authorized returns, Mr. Kaufman explained that because these returns are the <u>result</u> of a cost of equity analysis, they should not be used as an <u>input</u> to the analysis. Direct use of prior costs of equity makes the model circular. Kaufman Direct, at 54. While reasonable to review past Commission decisions both in Indiana and throughout the United States (as many witnesses have done in prior cases, including Mr. Kaufman), directly incorporating those results into a model is not appropriate. Too many unquantifiable variables (settlements, trackers, test years, rate design), coupled with the inherent staleness of the data (an order might easily be based on direct testimony filed eight months earlier, compiled from even older data, then collected and averaged with decisions two-to-three years old) lead us to conclude that no weight will be given to Dr. Avera's Risk Premium analyses derived from past decisions. The concerns expressed above about using a forecasted interest rate also apply to Dr. Avera's use of a forecasted interest rate in his Risk Premium model.

Mr. Kaufman pointed out Dr. Avera's Expected Earnings approach is simply a compilation of Value Line's 3-5 year estimated return on common equity (Kaufman at 55) and includes companies that do not belong in an electric utility proxy group. These intermediate-term, forecasted common equity returns are not "required" returns, nor are they a cost of equity. While the distinction is subtle, there is a difference between what a shareholder may expect to earn on an investment and what he requires. This distinction is particularly relevant when considering models used in setting utility rates and determining utility cost of equity. If a company was forecasted to over/under earn during the forecast period, using that figure to determine an authorized cost of equity would simply reinforce out-of-place expectations into future rates. Shareholders in any company may have unrealistic expectations (high or low). These expectations should not be built into utility rates. The Commission relies on market models such as the DCF and CAPM precisely because they produce required estimated costs of equity to induce investment. We find no benefit in considering this Expected Earnings model.

Flotation Costs

Dr. Avera increases his cost of equity with a 15-basis point flotation cost adjustment. Mr. Kaufman disagreed, arguing Petitioner failed to justify this cost. When a utility has recently incurred, or expects to incur flotation costs in the near future, this Commission has typically allowed utilities to recover measurable and reasonable flotation costs. In Cause No. 40003 (PSI), the Commission set forth its opinion on this matter:

> Although this Commission has recognized the need to adjust the cost of equity to reflect the costs associated with equity issuances, it has heretofore authorized such adjustments only when there was a projected near-term need to issue new stock. In this particular proceeding, Dr. Morin has not persuaded us to change this practice.
>
> We also observe that Dr. Morin's proposal appears to recapture historical costs that may have been incurred decades prior to the test year. For these reasons, we reject Dr. Morin's proposal regarding flotation costs, and find that Mr. Kahal proposed a more appropriate adjustment for purposes of the DCF calculation.
>
> Order at 30.

Dr. Avera relies on three year old public offering to support his adjustment (Direct, at 60). Based on American Electric Power Analyst & Investor meeting, February 10, 2012 (OUCC Exh. CX 7), AEP does not have plans in the next 3 years (2012 – 2014) to issue additional equity. Absent both a near term need, and any recently issued equity, it is unnecessary to include a flotation cost adjustment for Petitioner's proposed cost of equity at this time.

Impact of OSS Margin Rate Adjustment Mechanism

Dr. Avera argues that the $33 million (Blakley) or $37.5 million (Dauphinais) embedded OSS margin is a significant portion of I&M's authorized net operating income. The Commission takes note that Mr. Blakley's and Mr. Dauphinais' adjustment is a pro forma adjustment to present rate revenues and is separate from the calculation of net operating income. Therefore, we do not believe that the inclusion of OSS margin credit will damage I&M's credit ratings and financial integrity at the time basic rates are instituted.

I&M's Credit Rating

Maintenance of I&M's credit rating(s) became an important issue in this Cause. Petitioner's Witness Renee Hawkins stressed the importance of regulatory treatment to ratings agencies and investors, noting that "[a] significant portion of a company's credit rating is based on the qualitative factors around regulatory environment. Rating agencies closely follow the regulatory outcomes for a utility." Hawkins Direct, at 9-10. She noted that I&M's credit ratings metrics in 2010 and 2011 were mitigated by bonus depreciation from federal tax policy. Public's Witness Bradley Lorton presented evidence that I&M's credit metrics have been strongly positioned in the BBB (S&P) and Baa2 (Moody's) ratings for several years. Mr. Lorton argued that I&M was not in danger of a ratings downgrade, and presented analysis from S&P and Moody's showing the unlikely combination of events and developments that might result in a downgrade. The S&P analysis stated that a downgrade of I&M "could result" from a deterioration in the company's credit metrics on a "sustained basis." (Pub. Exh. BEL, p. 6). Mr. Lorton also observed that the ratings agencies' reports do not reflect the impact of the recent I&M rate case in Michigan (Case No. U-16801) or the benefits from this proceeding.

We find Mr. Lorton's position more convincing. Mr. Lorton's Attachment BEL-6 showing I&M's credit rating performance in Moody's reveals that the company has maintained its Baa2 rating since 1995. This consistent performance for over 17 years coupled with the company's steady cash flow and financial profile strongly suggests that a lowering of the company's credit rating is not imminent. Mr. Lorton also observed that I&M's parent, AEP, control's the company's debt and equity mix, and in Attachment BEL-3, S&P noted that AEP manages the company's liquidity. We are convinced that I&M is strongly positioned in its current credit rating and that it should be able to maintain that rating for the foreseeable future.

Cost of Capital Conclusions

The cost of equity is the cost of inducing and retaining investment in the utility's physical plant and assets. In other words, the COE compensates common equity investors for the use of their capital to finance the assets necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield* and *Hope* cases, a utility's allowed return on equity should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

The cost of equity may be estimated based upon one or more recognized economic methodologies of determining a current market derived cost of equity, which is designed to reflect the equity investor's expected return. We recognize the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment. Due to this lack of precision, the use of multiple methods is desirable because no single method will produce the most reasonable result under all conditions and circumstances. Based on the evidence of record and our analysis above, we find a range of 6.87% to 9.31% to be reasonable for Petitioner at this time. We further find Mr. Kaufman's 9.2% recommendation, located well to the high end of the range of reasonableness, to be an appropriate cost of equity.

### B. Overall Weighted Cost of Capital.

Indiana Michigan presented a capital structure as of the end of the test year, March 31, 2011. OUCC witness Eckert updated Petitioner's capital structure to reflect the December 31, 2011 balances which matches Petitioner's plant in service amounts as updated on February 2, 2012. Mr. Eckert also testified that there was a significant change in Petitioner's Capital Structure as Petitioner extinguished all three series of its preferred stock on December 1, 2011. He testified that I&M used cash on hand to redeem the $8M of preferred shares outstanding and has no plans to issue new preferred shares.

We find that Petitioner's capital structure should reflect the capital balances as of December 31, 2011 to match Petitioner's plant in service amounts. Based on these findings and after giving effect to the ROE we authorized above, we find that Petitioner's capital structure and weighted cost of capital are as follows:

| Description | Total Company Capitalization | Percent Of Total | Cost Rate | Weighted Cost Of Rate Base |
|---|---|---|---|---|
| Long Term Debt | $1,563,320,246 | 37.31% | 6.33% | 2.36% |
| Preferred Stock | $ 0 | 0.00% | 0.00% | 0.00% |
| Common Equity | $1,760,980,133 | 42.02% | 9.20% | 3.87% |
| Customer Deposits | $ 29,951,910 | 0.72% | 6.00% | 0.04% |
| ACC. DEF. FIT | $ 783,690,189 | 18.70% | 0.00% | 0.00% |
| ACC. DEF. JDITC | $ 52,632,906 | 1.25% | 7.85% | 0.10% |
| Total | $4,190,575,384 | 100.00% | | 6.37% |

Based on the record we further find that the foregoing capital structure properly reflects the target capital structure for the period the rates authorized herein will be in effect.

### C. Fair Rate of Return and Fair Value Increment.

(1) I&M Case-in-Chief. Dr. Avera said that a number of states have fair value language in their constitutions or regulatory legislation. He noted that perhaps the

most recent regulatory examination of fair value rate of return has been in Arizona where the state constitution requires that the Arizona Corporation Commission ("ACC") apply a fair value rate of return to fair value rate base.

He explained that for many years, the ACC had adopted a policy of "backing into" the fair value rate of return to yield the same revenue requirement as original cost ratemaking. Avera Direct, at 77. He testified this practice was rejected by the Arizona Court of Appeals in *Chaparral City Water Company v. Arizona Corporation Commission*, and in subsequent orders the ACC explored other alternatives. He stated that the ACC developed a policy of flexibility to apply fair value principles in a manner that fits the facts and circumstances of the utility and achieves regulatory objectives. *Id.*[3]

Dr. Avera recognized that most, but not all, utility rate proceedings apply the cost of capital to original cost rate base. *Id.* at 78. However, Dr. Avera explained that in his consulting and teaching outside of the utility regulatory arena, the cost of capital concept is applied to investment bases other than original cost. He stated that a recent and widespread application of standard ROE methods to a rate base other than original cost in the regulatory arena is in the area of telephone regulation.

Dr. Avera testified that one of the methods used by the ACC has been to allow a fair return on the fair value increment that is equal to the long-term U.S. Treasury bond yield reduced by the expected inflation rate. Dr. Avera testified that this return on the fair value increment will allow I&M an opportunity to earn a return that is comparable to similarly situated entities. By adopting this approach, the Commission would properly use the fair return to the fair value increment as a tool to support I&M's continued financial resilience, which is so important to customers and investors alike. He said this approach to fair value return would achieve the key regulatory policy objectives in this case - maintaining I&M's access to capital markets and financial integrity, so as to protect customers who depend on reliable and economic electric service.

Dr. Avera claimed that the recent financial crisis highlights the importance of regulatory support, as lower rated companies can be denied access to capital during times of financial market turmoil. He said giving a reasonable measure of return to the fair value increment would provide a "clear signal" that the Commission is willing to use the regulatory tools at its disposal to support I&M's efforts to maintain investment grade ratings and improve its credit standing by improving its ability to earn its allowed return.

Dr. Avera testified that the capital appreciation of investments that results in market value exceeding book value is not a "cost-free" asset, but is instead the fruit of the equity investors' commitment of capital and risk-bearing. He explained that although this incremental value was not separately financed, it has what economists understand as opportunity cost because it requires that investors forgo other opportunities to leave their funds invested in the utility. He stated that value increment is the private property of investors and it is being used to serve the public in the utility.

[3] *See Re UNS Electric*, Docket No. 71914 (Arizona Corporation Commission Sept. 30, 2010), 2010 Ariz PUC LEXIS 358.

Dr. Avera testified that because the return from the fair value increment is not risk-free, risk-free Treasury bond yields are not an excessive benchmark. Avera Direct, at 82-83. He added that the Company has consistently earned less than the allowed return due to attrition. Applying a risk-free Treasury bond yield adjusted for inflation would be consistent with fair value standards and the need to ensure that the Company has a realistic opportunity to actually earn the allowed return. Dr. Avera explained that debt investors have a specified claim against the company's value and cash flow. He said the capital structure applied to the original cost rate base considers the debt claims and they are provided for by the use of the embedded cost of debt applied to the debt percentage of the capital structure. After the debt claims are satisfied, the residual inures to the benefit of equity holders. Dr. Avera stated that use of the equity return is consistent with the economic reality that equity investors retain the residual value after debt claims have been satisfied.

Dr. Avera testified that in arriving at his inflation-adjusted Treasury bond yield, he considered projected data from a variety of sources that he claimed were commonly relied on by investors and the financial community. He explained that the inflation forecasts ranged from 1.95% to 2.58%, depending on the source and the horizon of the forecast period. In calculating the inflation-adjusted risk-free Treasury rate, he employed the 2.58% upper limit of this range, which is both conservative and consistent with the source and maturity of the 30-year Treasury bond yields discussed earlier in his testimony. He said subtracting an inflation rate of 2.58% from the 4.3 percent average 30-year Treasury bond yield for July 2011 results in an inflation-adjusted risk-free return on the fair value increment of 1.72 %. Avera Direct, at 84.

As explained by Dr. Avera, the "fair value increment" reflected in I&M's proposed methodology for determining the fair return on fair value is the difference between I&M's original cost rate base and its fair value rate base as presented by Company Witness David Moody. Mr. Krawec explained that the first step is to determine the incremental fair value on Indiana jurisdictional net plant in rate base above the original cost of the same property. Krawec Direct, at 24. He said Mr. Moody calculated the Total Company net plant fair value and Company Witness Caudill jurisdictionalized this amount on Petitioner's Exhibit TAC-3 (Revised). He explained that Company Witness Caudill also calculated the Indiana jurisdictional original cost net plant in rate base. Mr. Krawec explained that next step is to apply the rate of return of 1.72% supplied by Dr. Avera to the increment and gross up the return for income taxes using the conversion factor supplied by Company Witness Jeffrey B. Bartsch, AEP Director - Tax Accounting and Regulatory Support. To attempt to mitigate controversy and in the interest of affordability, while recognizing the need to maintain adequate financial strength to keep capital costs low, the amount of the fair value adjustment reflected in the Company's proposed revenue requirement is 50% of the computed fair value revenue requirement or approximately $17.989 million. Krawec Direct, at 24; Chodak Direct, at 30; Petitioner's Exhibit A-R1.

(2) OUCC Case-in-Chief. Mr. Kaufman advised that I&M is seeking a fair value increment above what would be produced under original cost rate making (Citing Mr. Chodak pages 29-31). He noted according to Ms. Caudill, I&M has a fair value rate base of $3,468,969,555 (TAC-3 revised). I&M's proposed fair value rate base exceeded its proposed original cost rate base by $1,255,944,732 (SMK-1 revised). Dr. Avera calculated an incremental fair rate of return of 1.72%. When 1.72% was multiplied by the $1,255,944,732 fair value incremental rate base, it produces a return on fair value of $21,602,249. When grossed up

for income taxes this figure produces a "Fair Value Incremental Revenue Requirement" of $35,978,546. Petitioner seeks to include 50% of that amount ($17,989,273) in its proposed revenue requirements.

Discussing Mr. Chodak's testimony regarding its proposed fair value increment, Mr. Kaufman referenced the request that the Commission "consider giving greater weight in the revenue requirement to the return on the fair value of the Company's utility property" if the Commission adjusted I&M's pro-forma operating expenses. Kaufman Direct, at 74 citing Chodak Direct, at 31:11-16. Mr. Kaufman argued Petitioner's operating expenses and its net operating income should be determined independently of each other. Mr. Kaufman noted that I&M asserts a jurisdictional revenue deficiency of $174,286,000, meaning their proposed fair value increment makes up approximately 10.32% of its proposed increase.

Regarding the need for a fair value increment, Mr. Kaufman testified that just six months earlier, Dr. Avera made just such a proposal on behalf of I&M Michigan (Cause No. U-18601). In that case, I&M did not seek a fair value increment, Dr. Avera proposed the identical cost of equity and he testified the *Hope* and *Bluefield* standards would be met. Mr. Kaufman argued since *Hope* and *Bluefield* apply in Indiana as in Michigan, Petitioner does not require a higher level of return in Indiana. *Id.* at 63.

Mr. Kaufman was not convinced that Dr. Avera's proposed inflation adjusted risk-free rate of return is a meaningful number to estimate a fair rate of return because it fails to remove historical inflation corresponding with the historical inflation included in the fair value rate base. *Id.* at 65-66. Mr. Kaufman highlighted the disconnect in Dr. Avera's methodology between historical inflation embedded in the fair value rate base and the forecasted inflation removed from the fair rate of return. He also criticized the method for removing forecasted inflation from a risk-free rate that bears no relation to Petitioner's weighted average cost of capital. Mr. Kaufman testified the Commission has repeatedly found that historical inflation must be removed.

Mr. Kaufman explained that the Commission can provide Petitioner with a reasonable return without including a fair value increment in authorized rates. Kaufman Direct, at 62-63. Mr. Kaufman asserted that by multiplying the Company's weighted cost of capital by its original cost rate base, the Commission can meet the *Hope* and *Bluefield* standards[4] for providing a reasonable return (i.e. net operating income). Mr. Kaufman also cited to Gary-Hobart Water Corporation, Cause No. 38126, (August 12, 1987) to support his assertion:

We find merit in the argument propounded by Mr. Thomas. This Commission has not witnessed a utility petitioning for rate relief which could not have been granted the necessary and appropriate rate relief based upon a reasonable cost of capital applied to its original cost rate base.

Next, Mr. Kaufman challenged Petitioner's overall methodology to estimate its incremental fair dollar return. Mr. Kaufman explained because fair value ratemaking includes

[4] Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n., 262 U.S. 679 (1923)

inflation in rate base, but removes inflation from the rate of return, the fair value NOI can be either greater or less than an original cost NOI. Kaufman Direct, at 65. A major flaw in Petitioner's methodology is that it will always generate a positive incremental return. While explaining how Dr. Avera's inputs work together to produce a conservative fair rate of return estimate, Mr. Kaufman pointed out it does not mean that those inputs are relevant or that they have the necessary nexus between the proposed fair rate of return and proposed fair value rate base. *Id.* at 66. Mr. Kaufman further explained that fair value ratemaking does not require the Commission to award a utility with an NOI that exceeds an amount that would otherwise be sufficient to meet the *Hope* and *Bluefield* standards. It is not an entitlement to provide Indiana utilities with an NOI above what could be authorized in other regulatory jurisdictions. *Id.*

Mr. Kaufman recommended that based on the flawed justifications and framework that Petitioner uses in this cause, the Commission flatly reject Petitioner's proposal to add an incremental fair value adjustment of approximately $18 million to its revenue requirements. Petitioner has neither adequately supported a need for an incremental return nor shown that the Commission cannot meet the *Hope* and *Bluefield* requirements without providing a fair value adjustment.

Mr. Kaufman also testified that if the Commission feels compelled to make fair value rate base finding that is other than original cost, he believed that Petitioner's Indiana Jurisdictional fair value rate base was no more than $2.9 billion. Mr. Kaufman also recommended that a fair rate of return of 5.1% on his proposed fair value rate base would produce a result that met the *Hope* and *Bluefield* standards.

Mr. Kaufman also commented on Mr. Chodak's testimony as it related to Petitioner's proposal to include a fair value increment. Mr. expressed concerns that Mr. Chodak's testimony appears to be setting the stage to ask for a larger fair value increment in Petitioner's rate next case. In the next case Petitioner may seek 100% of the alleged fair value increment or may not use the lowest fair value increment calculated by Dr. Avera. Thus, providing Petitioner its proposed fair value increment in this case may provide Petitioner a stepping stone to ask for an even larger fair value increment in its next rate case.

Mr. Chodak's testimony also included what appeared to be a proposal for a higher authorized NOI if the Commission makes any reductions to Petitioner's pro-forma operating expenses. On page 31, lines 11-16, Mr. Chodak stated:

> If for any reason the Commission would find it appropriate to adjust I&M's pro-forma operating expenses or other aspects of the Company's presentation, or if the Commission would do so for other reasons it deems appropriate, the Commission should consider giving greater weight in the revenue requirement to the return on the fair value of the Company's utility property using one of the methods proposed by Dr. Avera.

In OUCC DR 14 (Attachment ERK 10), the OUCC asked what regulatory treatment I&M is seeking based on this testimony. Having reviewed Petitioner's response, Mr. Kaufman stated that he was still unsure about their precise request. While Petitioner asserted it is not seeking a direct offset for any reduction to a proposed expense through a higher authorized NOI, Mr. Chodak made plain Petitioner's belief it is entitled to a return that is higher than their proposed revenue requirement.

Mr. Kaufman stressed that Petitioner's operating expenses and its net operating income should be determined independently of each other. The Commission should not provide a higher authorized NOI or rely on an alternative method used by Dr. Avera that produces a higher NOI, if the Commission otherwise reasonably and appropriately reduces Petitioner's pro-forma operating expenses.

In response to Mr. Chodak's concern that upcoming capital expenditures could lead to a credit rating agency downgrade, Mr. Kaufman discussed available rate tracker treatment. For many investments, such as the pollution control investments at Rockport, trackers allow I&M to increase its revenues and earnings outside of a general rate case. These trackers would offset some anticipated attrition, reduce volatility, assist with timely cost recovery and help maintain I&M's very stable investment-grade credit rating between rate cases. Kaufman Direct, at 75.

Mr. Kaufman summarized his opinion on Petitioner's proposed fair value increment. He testified that Petitioner has not demonstrated they need a fair value increment. Other than vague concerns about sending a message to the credit markets and offsetting anticipated attrition, Petitioner's testimony does not provide evidence that they need an incremental return to accomplish these ends or that these ends cannot be accomplished without an incremental return. Both Mr. Green's and Mr. Moody's analyses contain flaws that cause the results of their analyses to be overstated. Next, there is no nexus between the historical inflation included in the proposed fair value rate base and the forecasted inflation removed from Dr. Avera's fair rate of return. Finally, when determining an appropriate authorized NOI, the Commission should not lose sight of the endgame. An appropriate NOI must balance the interests of both the utility and the ratepayers and meet the *Hope & Bluefield* standards of maintaining financial integrity, access to capital at reasonable rates and comparable return.

Mr. Bradley E. Lorton, Utility Analyst with the OUCC, supported Mr. Kaufman's recommendations on fair rate of return and the fair value increment. He responded to Petitioner's request to provide a signal to credit markets through the fair value increment and presented testimony regarding I&M's credit ratings and measures used to establish its ability to attract capital. Mr. Lorton testified that bond ratings play a role in determining I&M's financial condition and must be considered when establishing the authorized rate of return on equity capital. He cited *Hope* and *Bluefield* regarding the standards for establishing a reasonable level of ROE.

Mr. Lorton provided Attachment BEL-1 which contained data supplied to the credit ratings agencies, including Funds from Operations (FFO) Interest Coverage, FFO to Total Debt and Debt to Capitalization. He testified that each credit rating agency uses similar ratios, with slightly different approaches. Mr. Lorton also provided Attachments BEL -3, BEL-4 and BEL-5, recent reports on I&M by each of the major credit ratings agencies, S&P, Moody's and Fitch.

He testified that S&P (Attachment BEL-3) showed stronger FFO to debt ratios in 2009 and 2010 than in the period 2006-2008. He also testified that S&P debt to capitalization ratio had decreased from 71.7% in 2006 to 63.3% in 2010.

Mr. Lorton also pointed to the Moody's credit opinion of January 31, 2012, (Attachment BEL-4) which also showed I&M's strong cash flow, and improving debt to capitalization ratios to conclude that I&M has a "stable ratings outlook" along with a "historically strong financial profile" and that I&M is "strongly positioned within its Baa2 rating." (Public's Exhibit BEL, p, 5).

Mr. Lorton also quoted the April 27, 2011 Fitch Ratings report which observed that I&M's operating lease for the Rockport plant causes a "below average" BBB- issuer default rating, but went on to say, "However, Fitch's analysis recognizes lease costs are recoverable in rates, and as such, the adjusted metrics are not entirely reflective of the utility's underlying credit strength," (Public's Exhibit BEL, p. 5).

Mr. Lorton testified that I&M's calculations provided to the credit ratings agencies (Attachment BEL-1) were "generally consistent" with the ratings agencies' reports. Mr. Lorton testified that I&M's ratios reported on February 29, 2012 are "in line" with S&P's "base forecast". He noted that the Debt to Capitalization ratio was border line, but observed "it is important to remember that AEP [I&M's parent company] controls I&M's debt/equity mix. AEP can either inject capital or take fewer dividends from I&M to further reduce the Debt to Capitalization ratio. . ." (Public's Exhibit BEL, p. 6). Mr. Lorton also quoted the S&P report showing that a downgrade could occur if I&M fell short of the base forecast on a sustained basis.

Mr. Lorton also analyzed the credit metrics I&M provided from a Moody's view, stating that I&M's Debt to Capitalization ratio is "safely below" the range that could "trigger a bond rating downgrade." (Public's Exhibit BEL, p. 7).

Mr. Lorton testified that the current metrics do not suggest an imminent downgrade. He also stated that the improved financial condition from the settlement of I&M's Michigan rate case, and any increased benefits from this Cause are not reflected in the credit ratings agencies reports and will strengthen I&M's financial position.

Mr. Lorton provided definitions for the bond ratings from each of the agencies. He testified that all three agencies view the company as "stable" and therefore "unlikely to change in the near term." (Public's Exhibit BEL, p.9). Mr. Lorton also provided Attachment BEL-6, I&M's Rating History from the Moody's website. This report includes a chart showing I&M's Baa2 rating has been stable since 1995.

(3) IG Case-in-Chief.

[NOTE - OUCC is not providing its own summary for this section of the proposed order with regards to IG's summary of its witness Gorman's FAIR RATE OF RETURN testimony. OUCC adopts the Industrial Group's summary of Mr. Gorman's FAIR RATE OF RETURN testimony.]

(4) I&M Rebuttal.

[NOTE - OUCC is not providing its own summary for this section of the proposed order with regards to I&M's rebuttal criticism of IG witness Gorman's FAIR RATE OF RETURN testimony. OUCC adopts the Industrial Group's summary of I&M's rebuttal criticism of IG witness Gorman's FAIR RATE OF RETURN testimony.]

Dr. Avera said that the Company's requested fair value increment would not allow I&M to earn a higher ROE than required by original cost ratemaking. Avera Rebuttal, at 8. He claimed the purpose of the fair value increment is to allow I&M an opportunity to actually earn the allowed ROE. He stated that Indiana is a fair value state so the Commission has the authority to use fair value to meet regulatory objectives. He added that in this case, the fair value increment can be used to address this problem. Given the Company's low bond rating and challenging capital investment needs, Dr. Avera viewed the persistent under earning as a threat to I&M's credit standing and financial integrity. He explained that contrary to Mr. Gorman's claim that the fair value increment would provide an "excessive earnings opportunity," the proposed increment would only serve to give I&M the same opportunity to actually earn its allowed return as its investor-owned electric utility peers in Indiana and the rest of the country.

Dr. Avera testified that the combination of past attrition, the prospect of future investment, and the key role of financial strength for I&M in the coming years makes the incremental dollars from the fair return important. He said the regulatory policy motivation of his recommendation is to make the authorized original cost return realistically achievable. He claimed that this use of fair return to fair value was endorsed in Bonbright's *Principles of Public Utility Rates* (2nd edition at 231). *Id.* at 60.

Dr. Avera claimed that the treatment of inflation in the fair return and fair value rate base proposed by I&M in this case is consistent with Commission precedent. He stated economic logic requires the return to consider future inflation and the rate base historical inflation. He said this is part of the proposed fair value increment methodology and is also not unlike the standard practice of original cost ratemaking following the *Hope* and *Bluefield* cases. Dr. Avera said the ROE is inherently forward-looking and an expectation of future inflation is embodied in cost of equity estimates. He explained the original cost rate base reflects only historical costs, yet it is routine in Indiana and other U.S. to apply the forward looking ROE as part of the cost of capital applied to original cost rate base.

Dr. Avera disagreed with Mr. Kaufman's contention that there is a "disconnect" between forecasted inflation and fair rate of return and that removing inflation from the risk-free rate "bears no relationship to Petitioner's weighted average cost of capital." Dr. Avera said that the rationale presented to the Arizona Commission is that investors put up no capital in order to gain a return on the fair value increment; hence the return should be based on the risk-free Treasury return because investors had no new capital at risk. Because the fair value increment incorporated the effects of past inflation, investors should not get the benefit of expected inflation because the result would be double-counting inflation. He stated that Mr. Parcell, the man who developed the methodology, rejected the idea of basing the return on fair value increment on the weighted average cost of capital because it is a measure of the cost of dollars actually invested rather than the fair value increment which, in his thinking, was a product of no new invested dollars. He added that the method for determining the fair return on fair value fits the requirements of this I&M case because it is simple, easy to calculate, and produces a clear increment of dollars that are available to offset the effects of attrition and allow the Commission to establish an effective earnings level that will meet the end result requirements of *Hope*, *Bluefield*, and Indiana precedent. *Id.* at 62-63.

Dr. Avera disagreed that the net operating income should be the same between using original cost rate base and fair value rate base. He explained that would make the requirement to consider fair value meaningless – the same position the courts have rejected in Arizona and Indiana where use of fair value is mandated by law. He added that it would not solve the problem facing I&M of persistently being unable to earn its authorized return.

Dr. Avera theorized that if the IURC were to adopt a fair return to fair value rate base to produce a lower or the same net operating income requirement for I&M as it would under original cost ratemaking it would not meet the *Hope end result* test. He suggested the *end result* test requires that the utility actually have an opportunity to earn a return that compensates investors for their risk-bearing, maintains the utility's credit standing, and preserves its financial integrity. Dr. Avera stated only if I&M starts with a higher return will it be able to offset the effects of its increasing capital base and actually achieve the earnings required to fairly compensate investors, maintain I&M's credit, and preserve its financial integrity. *Id.* at 77.

Dr. Avera stated that contrary to the claims of Mr. Kaufman and Mr. Gorman, the proposed return on fair value increment treats inflation consistently and provides I&M a realistic opportunity to actually earn the authorized ROE. He concluded that fair return on fair value is an appropriate regulatory tool for providing I&M an effective opportunity to earn an ROE that meets the end result test in Indiana. Avera Rebuttal, at 4.

(5) Commission Discussion and Findings. The cost of capital is a percentage which can be converted into an earnings requirement only by applying that percentage to a rate base. In *Duquesne Light Co.* v. *Barasch,* the Supreme Court held that the U.S. Constitution does not require the adoption of a single theory of valuation. 488 U.S. 299, 316 (1989). "The Constitution within broad limits leaves the States free to decide what rate setting methodology best meets their needs in balancing the interests of the utility and the public." *Id.*

Based on our readings of *Hope*, *Bluefield* and *Duquesne*, and out recent order in Cause No. 44022, we will use the following standards to determine a fair rate of return on Petitioner's investment in its utility plant, which under efficient and economical management will produce a return:

1) Comparable to return on investments in other enterprises having corresponding risks;
2) Sufficient to ensure confidence in the financial integrity of the Petitioner;
3) Sufficient to maintain and support the Petitioner's credit [rating];
4) Sufficient to attract capital as reasonably required by the Petitioner in its utility business.

One recognized method for evaluating the reasonableness of a utility's allowed return involves investigation of the utility's capital structure. From such investigation, we can develop the overall weighted cost of capital. This cost of capital may then be considered in determining a fair return. Having previously determined that the fair value of Petitioner's rate base is $2,905,166,836) it is now our duty to determine a fair rate of return that can be used to calculate a fair dollar return for Petitioner's net operating income.

> As our Supreme Court determined in *City of Indianapolis*,
>
> The ratemaking process involves a balancing of all these factors and probably others; a balancing of the owner's or investor's interest with the consumer's interest. On the one side, the rates may not be so low as to confiscate the investor's interest or property; on the other side the rates may not be so high as to injure the consumer by charging an exorbitant price for service and at the same time giving the utility owner an unreasonable or excessive profit.
>
> 131 N.E.2d at 318.

Therefore, the results of any return computation may be tempered by the Commission's duty to balance the respective interests involved in ratemaking. The end result of the Commission's Orders must be measured as much by the success with which they protect the broad public interest entrusted to our protection as by the effectiveness with which they allow utilities to maintain credit and attract capital.

It is important to understand that each party, including Petitioner[5], uses original cost ratemaking to determine Petitioner's NOI. At no time during this case has Petitioner argued that its proposed NOI failed to provide it with an adequate return or that it failed to meet the *Hope* and *Bluefield* standards. Instead Petitioner requests that the Commission include a bonus to rates, in the form of a fair value increment, to offset attrition that it alleges will occur.

At page 60 of his rebuttal, Dr. Avera cited Bonbright's *Principles of Public Utility Rates, 2d. Ed.,* page 231, for the proposition that the book endorses the "use of fair return to fair value." A more thorough review of the Bonbright text identifies multiple comments that offer a less-enthusiastic endorsement for fair value and the original cost v. reproduction cost studies on which it might be based:

> [T]he practical advantages of an original-cost standard of ratemaking are so great, and the theoretical advantages of a reproduction–cost standard so dubious, that many writers predicted a general shift from the latter standard to the former following the renunciation of the fair-value doctrine by the Supreme Court as a

[5] See page 148 of Petitioner's proposed order. Petitioner requests the Commission authorize an NOI of $176,502,511. Petitioner's proposed NOI is determined by multiplying its proposed original cost rate base of $2,391,632,939 (Pet. PO page 22) by its proposed weighted cost of capital of 7.38% (Pet. PO page 84).

mandatory "law of the land."

> Stated briefly, the claimed superiority of an original-cost standard of ratemaking lies in two, closely related, virtues of administratively feasibility and of capital-attracting or credit-maintaining efficiency.
>
> We have already indicated that while *Smyth vs. Ames* (1898) opened the floodgates for long, tortured, empty, meaningless fruitcake discussions surrounding original versus reproduction cost, the *Hope* case (1944) laid these to rest.
>
> Bonbright at 228, 223 and 200 respectively.

Dr. Avera developed the fair value increment from reproduction cost estimates provided from witnesses Moody and Green.

Dr. Avera testified in both direct (at 76-80) and rebuttal (at 61-63) that his fair value increment methodology was developed by Mr. David Parcell and presented on the Arizona Corporation Commission's ("ACC") behalf in *Chaparral City Water Company v. Arizona Corporation Commission* ("Chaparral"). Dr. Avera's rebuttal described his fair value method as "simple [and] easy to calculate" (Avera Rebuttal at 63:3) and producing a minimal return. During his redirect, Mr. Kaufman testified that Dr. Avera's testimony omitted several relevant facts regarding *Chaparall,* including a) Dr. Avera's fair value method was one of <u>two</u> options presented by Mr. Parcell in *Chaparall*, b) Dr. Avera's method was not Mr. Parcell's preferred method and c) the ACC did not adopt Dr. Avera's method to make its fair value determination. AA at 92-96. In his *Chaparall* testimony at page 8, Mr. Parcell explained why he did not prefer the methodology Dr. Avera uses:

> [T]his Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, <u>an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles</u>; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. <u>Underline added</u>.
>
> AA at 94:18 – 95:5.

A methodology such as Dr. Avera's that produces a fair value increment unsupported by economic or financial principles is inconsistent with Indiana rate-making principles. Dr. Avera testified that the proposed $18M fair value increment, while "minimal" (Direct, at 7:7 and 79:20), would also "provide a clear signal that the Commission is willing to use the regulatory tools at its disposal to support I&M's credit standing." Because Petitioner provided no analysis to assist the Commission in determining the cost / benefit relationship of this "clear signal," we must look to the evidence of record to perform our own.

Petitioner currently holds $1.563B in long-term debt. Witness Eckert Schedule MDE-7, page 1. Its current Standard and Poor's bond rating is BBB. Witness Lorton Attachment BEL-3, page 2. The spreads between 25-30 year, BBB and A-rated utility bonds (as of 3/30/12) were 37 basis points ["bp"] (one week earlier), 65 bp (three months earlier) and 48 bp (one year earlier) - an average of 50 bp. Witness Kaufman Attachment ERK-2. Even if Petitioner's proposed $18M fair value increment successfully sent a "clear signal" to the financial markets that rewarded I&M with a full one-grade bond ratings improvement (from BBB to A) for its future borrowings, the public interest would not be well-served.

Under that scenario, if I&M borrowed an amount equal to its current long term debt, the annual savings attributable to the "clear signal" (50 bp, A-rating) improvement would be approximately $7,660,000 ($1.53B * 0.005 = $7.66M). Best case: Ratepayers lose more than $10 million per year ($18M – $7.66M = $10.34M).

The worst case, a far more realistic possibility, is that ratepayers suffer a net loss of the entire $18 million each year. Petitioner's claims that this increment and its associated "clear signal" to the financial community are necessary to maintain its current rating are unfounded. There is no evidence that I&M's bond ratings are in danger of being downgraded. The Moody's report summarized I&M's situation thus:

> I&M's key metrics based on cash flow…have been consistently strong for its rating category…Debt/Capitalization has been consistently somewhat weak for the category.
>
> Lorton Direct, at Attachment BEL-4, page 4.

Similar comments regarding solid metrics and a stable outlook are found throughout the Fitch and S&P reports. Lorton Direct, at Attachments BEL-5 and BEL-3. Graphically, I&M's stability was impressively demonstrated in Witness Lorton's BEL-6, a Moody's single-line chart depicting I&M's bond rating from 1995 through 2012 – the line is perfectly straight, flat at Baa2. Mr. Lorton also observed that I&M's parent, AEP, control's the company's debt and equity mix, and in Attachment BEL-3, S&P noted that AEP manages the company's liquidity. We are convinced that I&M is strongly positioned in its current credit rating and that it should be able to maintain that rating for the foreseeable future.

Attrition is another rationale offered by Petitioner to support its proposed fair value increment. Dr. Avera testified the $18M was necessary to "assure that I&M has a realistic opportunity to earn a return comparable to the similarly situated entities in the Utility and Non-Utility Proxy Groups, a return to fair value increment should be used to offset anticipated attrition." Direct, at 80:14-17.

Petitioner's claims regarding both past and anticipated attrition are unsupported by any study or analysis detailing the amount, efforts undertaken to reduce its impact, or the success or failure of those efforts. There is similarly no study analyzing why these efforts were or were not successful, why future attrition might reasonably be expected to occur or why past efforts and/or new trackers (LCM, environmental) would not reduce the likelihood / affect of "anticipated attrition". Claims the anticipated attrition will be caused by "inflation and other factors" between rate cases (Chodak Direct, at 33:10-12) are unsupported by any explanation of the "other factors" or any study detailing how and how much attrition they will cause. Similarly, there is a paucity of detail supporting Dr. Avera's position that without the fair value increment, Petitioner will not have "a realistic opportunity to actually earn the allowed return" (Avera Direct, at 7:10-11 and 80:14-17). There is little, if any evidence supporting the proposition that Petitioner and companies in Dr. Avera's Non-Utility Proxy Group are "similarly situated entities".

As one specific example of attrition, Mr. Chodak testified I&M's earned return during the test year was 5.47% (Rebuttal at 3:2) and that in this case, 1.0% of ROE equates to approximately $17.0 million in earnings (Rebuttal at 8:7-8). These portions of his testimony do not discuss the fact that I&M's 2011 cash flow benefited by $141 million in deferred income taxes. See Hawkins Rebuttal at 2:9-10. While the cash flow from deferred income taxes is not included when an investor-owned utility calculates its ROE, the utility's shareholders still receive that financial benefit. Accepting Mr. Chodak's ROE-to-Earnings comparison, the 2011 deferred tax cash flow would create the equivalent of an additional 8.29% return (141 / 17 = 8.29) above Mr. Chodak's 5.47%, or a 13.76% effective test year ROE.

Petitioner's proposed Fair Value Increment is more accurately viewed as a cushion against alleged future attrition presented under the guise of Fair Value. See Chodak at 33:11-16:

> "If for any reason the Commission would find it appropriate to adjust I&M's pro forma operating expenses or other aspects of the Company's presentation, or if the Commission would do so for other reasons it deems appropriate, the Commission should consider giving greater weight in the revenue requirement to the return on the fair value of the Company's utility property..."

We decline Mr. Chodak's invitation. Petitioner's operating expenses might be reduced for any number of legitimate reasons – mathematical errors, improperly expensed capital items, non-recurring expenses, non-recoverable expenses, etc. – none of which entitle Petitioner to an additional fair value increment or revenue requirement.

Inflation is another crucial element to any determination of a fair rate of return. Historical inflation must be removed from the cost of capital. This ensures inflation is not double counted:

> [T]he weighted cost of capital contains the accumulated historic effects of all capital structure components. Since we must, by law, consider those effects when fixing the fair value of utility property...[w]e believe it is much simpler and generally more reflective simply to remove a reasonable quantification of the effects of historic inflation from the overall weighted cost of capital when attempting to determine a historic inflation adjusted cost of capital. *Indiana-Michigan Power Co.*, Cause No. 39314 (11/12/93) at 88.

The average age of Petitioner's depreciable plant is approximately 20 years. Kaufman Direct, at 72-73. The average historical inflation over the last 20 years is approximately 2.5% (Attachment ERK 6). Because Petitioner's witness Moody weights his estimated fair value rate base 57.33% original cost and 42.67% current cost (Moody Direct, at 19 – Revised, See also Pet PO page 34), it would be inappropriate to remove 100% of historical inflation from the cost of capital. Removing 50% of historical inflation (1.25%) from the cost of capital (6.37%) produces a fair rate of return of approximately 5.1%. This fair rate of return, combined with a fair value rate base of $2,905,166,836 produces a Net Operating Income of $148,163,509.

More than 25 years ago, in *Indianapolis Water Co.*, Cause No. 37612 (March 20, 1985), we held meeting the *Hope* capital attraction criteria is not the only relevant factor this Commission should consider when determining an appropriate NOI:

> While capital attraction criteria enumerated in *Hope* are a major consideration in determining just and reasonable rates, the *Hope* criteria scarcely exhausts the relevant considerations for balancing the investor and consumer interests. The end result of this Commission's Orders must be measured as much by the success with which they protect the broad public interests entrusted to our protection as by the effectiveness with which they maintain credit and attract capital.

We find this Net Operating Income of $148,163,509 to be sufficient, under the *Hope* and *Bluefield* efficient and economical management standards, to allow Petitioner to provide a comparable return, ensure confidence in Petitioner's financial integrity, maintain and support its credit rating and attract necessary capital.

## 10. Operating Results At Present Rates.

**A. Undisputed Pro Forma Adjustments.** I&M proposed a number of pro forma adjustments to its test year revenues and expenses that were either accepted or unopposed by the other parties. All the undisputed pro forma adjustments proposed by I&M have been identified in the record and are reflected in the revenue requirement calculation even though they may not be specifically discussed herein. The disputed adjustments are discussed hereinafter.

### B. Disputed Pro Forma Revenue Adjustments.

(1) AEP Pool Capacity Settlements.

(a) I&M Case-in-Chief. Jennifer McLravy testified on behalf of I&M regarding AEP Pool Capacity settlements. She said the AEP Interconnection Agreement requires each member to provide adequate generating facilities (or resources) to meet its firm load requirement. The Agreement allocates the AEP Power Pool capacity costs on the basis of each member's highest non-coincident peak ("NCP") in the preceding twelve months. The Member Load Ratio ("MLR") is the ratio of a member's highest NCP in relationship to the total of all members' highest NCP. The Agreement provides a capacity settlement that equalizes responsibility for installed capacity. The capacity settlement equalizes reserve margins by assigning responsibility to each member for its MLR share of System capacity. Ms. McLravy said to the extent a member's capacity is less than its System responsibility, the deficit company is required to make up its shortfall by paying a capacity charge to the surplus companies, based on the embedded cost of capacity of the surplus companies.

Ms. McLravy described the capacity equalization settlement calculations under the AEP Interconnection Agreement. She discussed how the surplus members of the Pool are reimbursed by the deficit members and how deficit members' capacity settlement charges are calculated. Ms. McLravy sponsored an adjustment of test year operating revenues to reflect the annualization of the pool capacity settlement using: (1) a normalized MLR, (2) adjusted levels of member capacity, and (3) adjusted capacity equalization rates. She calculated the normalized MLR using an average of monthly MLRs for April 2011 through March 2012. She said the monthly MLR is calculated based on the peaks from the preceding twelve months, and the April 2011 through March 2012 MLR reflects two separate periods of peaks: (1) actual peaks during the 12 month test year, and (2) forecast peaks during the 12-month period following the test year. She suggested the peaks in the test year (or actual period) were appropriately normalized and are consistent with the forecasted peaks in the adjustment period which are already normalized. She claimed the normalization was performed using statistical techniques to simulate adjusted peak data which effectively removes abnormalities, random events and weather impact.

Ms. McLravy's calculation shows I&M's normalized MLR is 0.19499. She said the normalized MLR is higher than I&M's average test year MLR of 0.19216, reflecting the normalized peaks during the test year, normal weather and the variable effects of economic recovery across the eastern companies of the AEP System during the twelve months following the end of the test year. She said her calculation of the Pool capacity settlement adjustment annualized the end of the test year Pool capacity but made no other changes. Ms. McLravy said she updated the equalization rate reflected in her adjustment to include updated changes in investment cost and expected fixed operating costs.

Ms. McLravy discussed three events, which she claimed changed the level of I&M capacity settlement receipts: (1) the retirement of Ohio Power Company's ("OPCo") Sporn Unit 5 in September 2011, (2) the merger of Columbus Southern Power ("CSP") into OPCo on December 31, 2011 and, (3) the completion of the Dresden Gas Plant as an addition to Appalachian Power Company ("APCo") capacity that occurred January 31, 2012. Ms. McLravy suggested even though I&M's capacity remained the same, the capacity changes for other members of the Pool whether I&M is a surplus or deficit member of the Pool. She claimed this in turn affects the capacity settlement receipts that I&M receives from or pays to the Pool. She also claimed that because of these three events along with normalized peaks, I&M's capacity settlement receipts from the Pool have decreased from $60.7 to $38.5 million.

(b) OUCC Case-in-Chief. Mr. Eckert responded to Ms. McLravy's testimony regarding pool capacity settlements. He recommended that the Commission reject I&M's adjustment and use the test year amount as the pro forma amount. He testified that Petitioner did not provide any specific information to support its capacity equalization adjustment. He testified that Petitioner also did not provide any specific reasons why it needed to adjust its MLR, member capacity levels, and capacity equalization rates. He further stated that Petitioner did not identify any specific events or abnormalities that impacted the test year MLR, test year member capacity, or test year capacity equalization rate.

(c) Fort Wayne Case-in-Chief. Fort Wayne Witness Kerry A. Heid, a rate consultant, recommended the Commission disallow the pool capacity settlement adjustment in its entirety and use the test year amount. He stated that the proposed operating revenue adjustment is not fixed, known and measurable because it was based solely on estimates for which he stated there is complete lack of support. Heid at 12-17.

(d) I&M Rebuttal. Ms. McLravy claimed the recommendations of Fort Wayne and OUCC with respect to the capacity settlement revenue adjustment would reflect a capacity credit that is too high and would deny I&M a reasonable opportunity to earn the return authorized in this case. McLravy Rebuttal, at 2. She claimed I&M's proposed adjustment is reasonable and that I&M is willing to periodically adjust rates to ensure that customer rates always reflect the actual amount of the credit/charge. She suggested the test year and adjustment period results are known and that the twelve months ended March 2012 actual net capacity settlement receipts/payments of $30.8 million are much lower than the test year receipts of $60.7 million. She said I&M included $38.5 million on a Total Company basis as a credit in its cost of service, which lowers its revenue requirement used to set rates. Ms. McLravy claimed that since the end of the test year, I&M's capacity credits from the AEP Pool have dropped substantially due to changes in the capacity in the AEP Pool. She suggested that as of the end of the adjustment period I&M was making capacity payments to the Pool and this would continue until new peaks are set and rolled into the calculation. Ms. McLravy claimed that even after that, I&M will not get the same level of capacity credits received during the test year.

She claimed historic test year capacity payments or credits are not representative of future payments or credits. In response to the criticism of her normalized MLR, Ms. McLravy suggested an alternative approach that would set rates based on actual results. She suggested it would be a simple matter to periodically adjust I&M's rates to match the projected credits received or payments made with actual levels. According to Ms. McLravy, a periodic rate adjustment mechanism could set an initial level based on expected levels and then reconcile that amount to actual results once they are known. She claimed a periodic adjustment mechanism would insure the customers be credited with every dollar I&M receives from the capacity settlement or pay only what I&M pays when in a capacity deficit position taking the debate out of establishing the proper level to include for ratemaking purposes for such a volatile item.

I&M proposed that the initial tracker amount reflect Ms. McLravy's adjusted test year expense. I&M Witness Krawec suggested the Capacity Tracker factors would be established annually based upon a projection of capacity payments/receipts to be tracked and would include a reconciliation of actual capacity payments/receipts for the prior year. If the Commission approves I&M's tracking proposal, Mr. Krawec said I&M would file compliance tariffs reflecting this initial tracker recovery. Within nine months after the implementation of the initial capacity tracker, I&M would file a petition and supporting testimony and exhibits for approval to implement the first annual adjustment to the Capacity Tracker. Mr. Krawec said in that first annual proceeding, the initial factor would be reconciled and a new factor would be proposed based upon a forecast of capacity payments/receipts during the period that the factor will be in effect adjusted for the amount of the reconciliation.

(e) Commission Discussion and Findings.

Ms. McLravy testified about her modifications to I&M's MLR that occurred as a result of the retirement of OPCo's Sporn Unit 5, the merger of CSP into OPCo and the completion of the Dresden Gas Plant as an addition to APCo capacity. Ms. McLravy stated that the MLR is based on the peak experienced by participants in the AEP Pool. Business activity in I&M's service area mirrored the recent U.S. economic recession in June 2009 and resulted in I&M's MLR in the test year being based on a period in which load was initially low and subsequently increased.

However, the economy has continued a slow recovery and load is as a result recovering. MLR is determined on the basis of non-coincident peak across the members of the pool. There is a necessary interplay between the MLR and subsequent capacity credits and settlements for each member of the pool. Ms. McLravy's modified MLR indicated that I&M now has a higher MLR than that originally filed. We have two questions before us: (1) whether the test year MLR is appropriate or should be updated based on the plant additions and retirements, and (2) whether the capacity settlement payments in I&M's test year are more appropriate than the out-of-period amount that I&M now propounds.

I&M argues that the test year level of capacity settlement receipts is not representative of I&M's ongoing capacity settlements due to changes in the amount of capacity owned by other members of the AEP Pool, and that its use in a rate determination would be injurious to I&M. Messrs. Eckert and Heid expressed reservations about the support I&M provided for its proposed normalization of the capacity settlements. I&M's information for the twelve month period following the test year does show that I&M's capacity settlements declined by approximately $30 million. But I&M has provided no data to support its assertion that the post-test year amount is more appropriate and reasonable than the amount in the test year. Differences in MLR will impact capacity settlements, but capacity settlements do not rely per se on the MLR. In other words, while the MLR is determined by reference to the NCP of the pool, this MLR is determined based on the total amount of energy each member of the pool is responsible for, based on the load then generated. All other things being equal, as load goes up or down, capacity goes onto or comes off the grid, and a given member's MLR may vary very little.

The OUCC and Fort Wayne argue that we should use the number provided in I&M's test year, as I&M has shown insufficient information to warrant the proposed alternative. I&M's rebuttal testimony offers to reduce the capacity settlement by $22.1 million, with the revenue requirement recognizing $38.5 million of revenue for the capacity settlement. I&M asserts that this reflects the fixed, known and measurable changes that occurred within 12 months of the test year and is normalized for weather and other factors. I&M believes that it is better served by including a lower capacity settlement amount on the grounds that it is "more representative" of future conditions. We disagree.

We have recently issued an order regarding I&M's capacity settlements. In approving a Renewable Wind Energy Project Power Purchase Agreement between I&M and a Northern Indiana wind farm, we held that the agreement "will produce benefits for I&M, its customers and the State of Indiana....[and] is also expected to improve Petitioner's capacity settlement position in the AEP Pool and increase the potential for off-system sales." *In re Ind. Michigan Pwr.*, Cause No. 44034 (Ind. Util. Regulatory Comm'n Sept. 21, 2011). We held that I&M should be allowed to recover the costs incurred in connection with the REPA, but did not order I&M to report on any increase to capacity settlements that occurred as a result.[6] We note now that I&M did not include the REPA as an update to capacity in this case as part of the impact to the AEP Eastern Pool and I&M's contribution to it, although the occurrence of the REPA was known within the 12 month period following the test year.

We do not pass judgment on this absence of this information in I&M's testimony, but rather to emphasize the hazard of potentially incomplete out-of-period adjustments. Arguably, I&M's REPA represents capacity that I&M contributes to the pool, which would again modify I&M's resulting capacity settlements and would impact new MLR calculations. I&M recommends that we establish another tracker proceeding to adjust on-going capacity settlements, much as we do with FACs. We are reluctant to do so. Exceptions tend to swallow the rules: removing more and more elements of a utility's rates from the standard rate-making formula skews the remaining results. If we were to track every change to capacity, then we should recognize the REPA in our current calculations.

"The use of a historical test period is the generally accepted method for setting rates for the future by taking the actual results for the particular test year and adjusting for any extraordinary and nonrecurring items and for all *known and measurable* changes." *Capital Improvement Bd. v. Pub. Serv. Comm'n*, 176 Ind. App. 240, 375 N.E.2d 616, 630 (Ind. App. 1978). The use of test year information is not a random application of figures to reach a given rate result. Test year data is meant to be a simulacrum of a utility's on-going expenses, which when applied to the development of rates, will yield an income sufficient to pay a utility's expenses and compensate utility shareholders. *City of Evansville v. S. Ind. Gas & Elec. Co.*, 167 Ind. App. 472, 339 N.E.2d 562, 569 (Ind. App. 1975).

Ratemaking recognizes that there is a delicate interplay among the many different expenses of a utility. The adoption of a test year is a way to 'freeze' expenses in time to make a calculation of an appropriate amount for rates going forward. The use of expenses outside the test year is allowable, *if* those amounts are fixed known and measureable. Capacity settlements are fluid, as I&M has shown, and I&M has provided no evidence that the out-of-period amount is a better and more accurate amount for determination of rates. We therefore find that the test year amount for capacity settlements and the MLR set forth in I&M's case-in-chief are appropriate for the rate calculation in this case.

(2) Reclassification of Revenues.

(a) OUCC Case-in-Chief. OUCC Witness Margaret Stull proposed an adjustment to Other Revenues of $275,717 to be treated as "above-the-line"

[6] "We find that I&M should be authorized to recover via a rate adjustment mechanism, the retail portion of the costs of the Wind REPA on an accrual basis in accordance with Ind. Code §§8-1-2-42(a) and 8-1-8.8-11 contemporaneously with the processing of I&M's FAC proceedings (or a successor mechanism). While the cost recovery of the Wind REPA should be administered through I&M's FAC proceedings (or a successor mechanism), recovery of purchased power costs detailed in the Wind REPA shall not be subject to the Section 42(d)(1) test or any FAC or purchased power benchmarks, economic dispatch requirements, or least cost requirements during the twenty-year term of the Wind REPA." *Id.*

for the benefit of the ratepayers.

Ms. Stull explained that Petitioner received a payment of $542,247 from EPRI during the test year. Per Petitioner's response to an OUCC data request this payment is the first of three expected payments from EPRI for its share of royalty payments from Westinghouse Electric Company ("Westinghouse"). Petitioner received the second payment of $567,228 in July 2011 and expects the third payment of $567,597 in July 2012, making Petitioner's total share of royalty payments $1,677,442. Stull, at 17.

Ms. Stull explained these royalty payments are based on a First-of-a-kind engineering ("FOAKE") sub-contract awarded to Westinghouse in 1992. The FOAKE sub-contract required Westinghouse to pay royalties on the sale of certain nuclear plants. Ms. Stull stated the Advanced Reactor Corporation ("ARC") coordinated this project under a Department of Energy ("DOE") Cooperative Agreement. She added that funding to ARC to undertake this activity was provided by EPRI, the DOE, and supporting members of ARC. *Id.*

Ms. Stull also noted that in 1992, ARC and EPRI entered into an agreement that included a formula for distribution to EPRI and ARC supporting members of royalties received by ARC on sub-contracts issued to vendors of nuclear plants. In 1998, ARC assigned to EPRI the responsibility to negotiate and collect royalties due from ARC's sub-contractors, and to distribute royalties received to EPRI and ARC supporting members. Ms. Stull stated that in 2010, after extensive negotiations, EPRI entered into a settlement agreement with Westinghouse resolving the royalties to be paid by Westinghouse for the FOAKE work based on sales by Westinghouse of AP1000 plants. Ms. Stull noted that Westinghouse has a firm commitment to make three annual payments with the possibility of additional payments depending on the number of total Westinghouse sales of the AP1000. *Id.* at 18.

Ms. Stull proposed an adjustment to Other Revenues of $275,717 to be included in revenue requirements. She calculated this amount by taking total payments of $1,677,442 (Total Company) and amortizing these payments over four years, the anticipated life of the rates being set in this Cause, yielding annual revenues of $419,361 (Total Company). Ms. Stull noted Petitioner did not include any "below-the-line" accounts in its Jurisdictional Separation Study. Therefore, she based her Indiana Jurisdictional allocation on the average rate applied to test year EPRI costs. These costs were recorded to two (2) accounts (524 and 908), which were allocated based on demand (524) and number of employees (908). She noted the average factor calculated is 65.747%. Applying this factor to annual revenues yields $275,717 (Indiana Jurisdictional) of other miscellaneous revenues to be included in the revenue requirement set in this Cause. Ms. Stull did not include any other potential Westinghouse royalty payments in her adjustment since it is not known whether there will be additional payments, when the payments would be received, or how much these payments would be. *Id.* at 18-19.

Ms. Stull stated she proposes this reclassification because Petitioner included 100% of its EPRI costs in its proposed revenue requirement, as it has done in past rate cases, leaving ratepayers to bear all the costs. She asserted that charging ratepayers with all of the costs of this organization but denying them the benefits is unreasonable and should not be allowed. Either both EPRI membership costs and revenues should be recorded above-the-line or both should be recorded below-the-line. *Id.* at 19.

(b) I&M Rebuttal. Mr. Brubaker recommended the Commission reject Ms. Stull's proposal and make no adjustment. He disagreed with Ms. Stull's conclusion that I&M's customers are entitled to these below-the-line revenues. He argued the royalty revenues recorded below-the-line have no relationship to I&M's EPRI dues. He said I&M is entitled to the royalties because it was one of the supporting members of the ARC that elected in 1992 to invest in ARC along with the EPRI and DOE. Mr. Brubaker suggested EPRI's investment in ARC was not on behalf of all EPRI dues-paying members and I&M was not a member of EPRI in 1992, when the Company became a supporting member of ARC. Brubaker Rebuttal, at 6. Mr. Brubaker's rebuttal testimony included as an exhibit a communication from EPRI documenting that the work associated with the royalties was not part of the annual EPRI membership dues but were instead separate payments made to ARC for the project. Petitioner's Exhibit JLB-R5, p. 5. Mr. Brubaker also stated that I&M's membership in EPRI began after the Commission granted approval in its Order dated November 12, 1993 in Cause No. 39314. Mr. Brubaker stated that the cost of I&M's investment as an ARC supporting member was never part of a revenue requirement used to establish I&M's basic rates. *Id.* at 7.

(c) Commission Discussion and Findings.

Based on the evidence of record, we accept the OUCC's proposed reclassification of the royalty revenues associated with I&M's payment as a supporting member of ARC. But we do not do so for the reasons relied upon by the OUCC in Ms. Stull's testimony.

The OUCC and Petitioner focused on whether the payments, which ultimately resulted in the royalty payments the OUCC maintains should be included above the line, had specifically been included in Petitioner's revenue requirement. The OUCC suggested in its testimony that such payments were included as EPRI dues. Mr. Brubaker pointed out in his rebuttal testimony that it sought authority to include its EPRI dues for the first time in its rates in Cause No. 39314 final order issued November 12, 1993, after the 1992 support on which the royalty payments are based. But Mr. Brubaker also indicated that the royalty payments for which it was due was not as a result of I&M's membership in EPRI but as a supporting member of ARC. Thus, whether Petitioner included its EPRI dues payments in its revenue requirements is a red herring.

We cannot identify, as the OUCC suggested, a specific *pro forma* revenue requirement that generated the payments that lead to I&M's right to royalty payments. But we are not required to identify such a revenue requirement to determine whether the royalty payments should be considered above-the-line revenues.

In its proposed order, Petitioner asked us to quote the following section from the 1993 rate order. We think this section is pertinent but not for the finding advanced by Petitioner.

> Between general rate filings, for a large utility . . . , there are literally thousands of revenue and expense items than can fluctuate and change. Revenues from a customer or group of customers may change. The change may be temporary or permanent. A decrease in sales to one customer or group of customers might be offset by an increase in sales to others. A decrease in an expense may be offset by a decrease in revenues. An increase in an expense may be offset

by an increase in revenues.

*Re Indiana Michigan Power Co.*, Cause No. 39314 (IURC 11/12/93) at 168.

This quote illustrates that for ratemaking purposes, revenue requirements and operating expenses are not tied together with precision. And it is not necessary to recite the source of funds used for an expense to determine whether revenues associated with an expense should be considered above or below the line. Though he could not identify any particular expense accounts, Mr. Brubaker testified that the dollars invested in ARC were expensed as they were paid. (Tr. DD-14, line 17 through DD-18, line 4) Thus, they were considered an operating expense of the utility.

While we note that utilities such as I&M have research and development budgets that are included as *pro forma* revenue requirements. The ARC payments could be considered an expense going toward research and development. It is not necessary to establish that the ARC payments were specifically embedded in such a revenue requirement. It is the source of the funds that should establish how revenues causally related to such funds should be treated. Petitioner has not established that the payments it made to become a supporting member of ARC were from a below the line source. Mr. Brubaker considered the ARC payments to be prudent expenses. (Tr. DD-19 -20) Petitioner's argument seems to rely on the faulty premise that the OUCC has the burden to establish precisely the revenue requirement that supports its expense for associated revenues to be treated above the line. Petitioner provided no proof to suggest that the expensed payments made to invest in ARC should be considered below the line or otherwise considered an expense that should not be allowed in rates. In the absence of such proof, we cannot find that the royalty payments associated with the ARC payments should be considered below the line. We accept the OUCC's proposed reclassification of the royalty revenues associated with I&M's payments as a supporting member of ARC.

### C. **Disputed O&M Expense Adjustments.**

(1) Carbon Capture and Storage ("CCS") Research and Development Costs.

(a) I&M Case-in-Chief. Mr. Chodak discussed the research and development project undertaken by the Company as part of the AEP System, to provide for the use of coal at an increased level relative to what it would be otherwise under regulation that constrains carbon emissions. Chodak Direct, at 23. He said this research includes evaluating a technology to remove carbon dioxide ($CO_2$) from flue gas and safely store it underground. He stated that this research involves a test project at the Mountaineer Plant owned by I&M affiliate, APCo.

Mr. Chodak said using the results of an initial test effort, AEP is conducting a Carbon Capture and Storage ("CCS") Front End Engineering Design ("FEED") Study. Chodak Direct, at 23. He argued the CCS FEED Study is essential research into the CCS process that is directly transferable to I&M's Rockport Plant because it is of the same design as the Mountaineer Plant. Mr. Chodak suggested the FEED Study positions the Rockport Plant to continue to provide low cost generation to I&M's Indiana customers. Mr. Chodak said it also will provide for the increased use of Indiana coal in the event that CCS is necessary to comply with carbon emission regulations.

Mr. Chodak said while I&M and its customers will receive the benefit of the entire FEED Study, the cost to I&M is only a fraction of the total cost because this research and development effort is being undertaken by the AEP System. Chodak Direct, at 24. He stated that I&M's share of the costs of the FEED Study is based on its ratio of coal-fired capacity that may use the CCS technology, which ratio is 11.5%, or $1.6 million (Total Company). As proposed by Company Witness Krawec, the proposed revenue requirement includes $520,798 to reflect an amortization of the Indiana retail jurisdictional share of this cost over a two-year period. Chodak Direct, at 24. Mr. Chodak considers it reasonable to include this amount in I&M's revenue requirement because the CCS FEED Study is allegedly beneficial to I&M's customers, is a step taken to reasonably anticipate expected environmental regulations, and suggests it will allow I&M to continue to depend on the coal-fired Rockport Plant for electric generation with reduced environmental impact. Chodak Direct, at 24; see also Petitioner's Exhibit A-5, p. 82 (O&M Adjustment 39).

(b) OUCC Case-in-Chief. OUCC Witness Cynthia M. Armstrong, Senior Utility Analyst in the OUCC Electric Division, recommended removal of I&M's adjustment for the CCS FEED Study costs from the revenue requirement calculation because the CCS FEED Study costs are an unreasonable expense to recover from I&M's ratepayers.

Ms. Armstrong stated that I&M is requesting a total of $1.6 million over two years to fund a CCS FEED Study for the Mountaineer Generating Station in West Virginia. She explained I&M's share of the total FEED Study costs is 11.5%, which represents I&M's portion of coal-fired units in the AEP System. Ms. Armstrong recommended removal of I&M's Adjustment O&M-39 for CCS FEED Study Costs because these costs are unreasonable for inclusion in I&M's rates.

Ms. Armstrong first noted that I&M is requesting recovery of this cost because the Virginia State Corporation Commission ("VSCC") and the West Virginia Public Service Commission ("WVPSC") denied previous requests for recovery of Mountaineer's CCS costs. Ms. Armstrong testified that in its 2009 rate case before the VSCC, APCo. requested the inclusion of $74 million in rate base, a return on rate base and recovery of expenses for the validation project to test CCS technology at the Mountaineer plant. Ms. Armstrong testified that the VSCC denied APCo.'s request because the commission concluded that it was unreasonable for Virginia ratepayers to shoulder the entire financial burden and risk associated with AEP's research and development, especially when AEP was not undertaking CCS initiatives at any of its other subsidiaries' plants. She also noted that APCo. requested the inclusion of the Mountaineer CCS FEED Study costs in rate base in its 2011 rate case before the VSCC. Ms. Armstrong explained that the VSCC denied APCo's request again, stating that the company had not shown at that time that it was reasonable to recover FEED Study costs from Virginia ratepayers.

The VSCC found that APCo. did not show ratepayer benefit from the study, and there were no existing laws or regulations requiring CCS at the time. VSCC also found that APCo.

acknowledged that AEP is no longer moving forward with the development of the commercial scale carbon capture project, and the outcome of potential future carbon legislation, the success of any commercial-scale project at Mountaineer, and the value of collecting and sequestering $CO_2$ were all unknown at the time.

Ms. Armstrong also testified that APCo. and Wheeling Power Co. ("WPCo.") included in a general rate increase request before the WVPSC in 2010 a jurisdictional rate base amount of \$30.9 million for Mountaineer–related CCS equipment, as well as \$4.3 million in depreciation expense and \$6 million in operating expenses. Armstrong stated that while the WVPSC was more open to recovery of these costs than the VSCC, it denied inclusion of capital costs in rate base (or recording the book value of this equipment in FERC Account No. 183). The WVPSC considered the project as a continuing preliminary investigation and entertained the idea of considering it as used and useful plant in service in the future.

Even with that finding, Ms. Armstrong pointed out that the WVPSC found that it was not fair to allocate all of the costs of this project to APCo. and WPCo. just because the companies happened to be 100% owners of the plant chosen by AEP for the demonstration project. The WVPSC did allow APCo. and WPCo. to recover the operating expense associated with continuing to operate the project, but found that the project costs should be allocated to all AEP Eastern System Companies according to their respective member load ratios ("MLRs"). Ms. Armstrong pointed out that the WVPSC also admonished APCo. for its failure to seek pre-authorization for the project and its costs.

Ms. Armstrong thus stated that the Commissions that actually have jurisdiction over APCo. and Mountaineer are not fully supportive of allowing APCo. to recover the costs of the CCS FEED Study or CCS Pilot project. Ms. Armstrong argued that based on the lack of a nexus with Indiana, the Indiana Commission also should not include Mountaineer's CCS FEED costs in I&M's Indiana jurisdictional rates. As she pointed out, while Virginia and West Virginia regulators have suggested that AEP seek recovery elsewhere, APCo's Mountaineer FEED study is not and should not be a part of I&M's Indiana retail cost of service.

The second reason Ms. Armstrong recommended disapproval of the CCS FEED Study costs is that the equipment involved in the study is designed to operate on a plant that is not owned by I&M and is not part of I&M's rate base. While the Interconnection Agreement ("IA") allows Mountaineer to provide capacity and power to the AEP Pool for the benefit of all AEP Eastern Companies, Ms. Armstrong reasoned that it is too remote and speculative to say that this Mountaineer equipment should be part of the Indiana retail revenue requirement.

The third reason Ms. Armstrong recommended denial of the CCS FEED Study Costs is that I&M does not currently have plans to install CCS on the Rockport Plant, although it may consider it after retrofitting the Rockport Units with flue gas desulfurization ("FGD") systems and selective catalytic reduction ("SCR") technologies. Furthermore, she noted that AEP has announced that it has placed its plan to develop the commercial-sized CCS technology at the Mountaineer Generating Station on hold, and the company terminated its cooperative agreement with the U.S. Department of Energy ("DOE") to receive DOE funding for 50% of the project.

Ms. Armstrong also recommended denial of the CCS FEED Study costs because such studies are highly site-specific. Ms. Armstrong reasoned that even if the design of the capture equipment at Mountaineer were transferable for the possible deployment of carbon capture equipment on Rockport, I&M would still have to conduct another costly study to determine the geological sequestration injection sites for carbon dioxide in the Rockport area and the transportation system to such a site. Ms. Armstrong suggested that if and when I&M conducts a FEED study at Rockport, then it may be reasonable to seek recovery of costs from I&M's retail ratepayers.

As another ground for denial, Ms. Armstrong pointed out that I&M never informed this Commission of its intent to conduct this study outside Indiana and pass the study's cost onto I&M retail customers. Therefore, the Commission and other interested parties have had no opportunity to review the study in depth, and the Commission has not found that these costs are reasonable for inclusion in I&M's Indiana rates through another proceeding. She also noted that West Virginia has realized local job and tax benefits as a result of the Mountaineer CCS FEED study, and I&M has not shown that these benefits extend to the Indiana retail jurisdiction. Therefore, Ms. Armstrong concluded that costs from the West Virginia project should not be passed on to Indiana retail ratepayers.

Ms. Armstrong also reasoned that now the EPA has proposed Greenhouse Gas ("GHG") New Source Performance Standards ("NSPS") and finalized the Greenhouse Gas Tailoring Rule, APCo. has a greater advantage over the other AEP System coal units, as it may have a greater capability to add or upgrade coal-fired units in the future. Ms. Armstrong testified that the EPA proposed NSPS for GHG emissions from new Electric Generating Units ("EGUs") on March 27, 2012, which will group natural-gas fired EGUs and coal and oil-fired EGUs for the first time into a new source category specifically for GHG emissions control. She stated the EPA has set the GHG NSPS for new EGUs at the level that a combined-cycle natural gas ("NGCC") facility can achieve, which is 1,000 lbs of $CO_2$ equivalent per MWh ($CO_2e$ /MWh). Armstrong noted that the NSPS only applies to new facilities, and the modification, refurbishment, and repowering of existing units are not subject to these standards. She also indicated that any facility that has already received a Prevention of Significant Deterioration ("PSD") or Non-attainment New Source Review ("NNSR") pre-construction permit and will commence construction within the next twelve months is also exempt from these standards.

Ms. Armstrong explained that if a new coal unit is constructed to serve either base or intermediate load, it must employ CCS at a 50% level. A new coal unit also has the option of averaging its emissions over a 30-year time span, so that the average annual emission rate would equal 1,000 lbs $CO_2e$ /MWh. To do this, Ms. Armstrong observed, the new unit must operate at a supercritical Pulverized Coal ("PC")level (1,800 lbs $CO_2e$/MWh) and must install CCS within 11 years with at least 66% $CO_2$ capture. Ms. Armstrong explained that existing coal-fired EGUs that undergo modifications, refurbishments, or repowering will still be subject to GHG PSD permitting requirements and will still be required to install Best Achievable Control Technology ("BACT") for GHG emissions. Ms. Armstrong testified that on May 13, 2010, the EPA issued the PSD and Title V Greenhouse Gas Tailoring Rule ("Tailoring Rule") that sets different thresholds for GHG emissions from new and existing units subject to the PSD and Title V permitting provisions of the CAA. Ms. Armstrong explained that under the Tailoring Rule, new or existing sources seeking a PSD pre-construction permit for projects which result in GHG emission increases of at least 75,000 tpy of $CO_2e$ or more would need to determine and install the BACT for their GHG emissions. The cost and feasibility of CCS at a particular site would likely preclude its designation as BACT for a particular facility.

Because of both of these rules, Ms. Armstrong said that Mountaineer has a greater advantage over other AEP System coal units in that it may have a greater capability to add or upgrade coal-fired units in the future. She noted that initial studies indicate that Mountaineer has suitable sites nearby for the geological sequestration of $CO_2$, and that other AEP coal-fired generating stations will still have to spend millions of dollars to find out whether there are similarly suitable geological sequestration sites. Armstrong concluded that Mountaineer will have less uncertainty associated with its ability to capture and sequester $CO_2$ at its location and is therefore in a better position to construct a new coal-fired unit that is compliant with GHG NSPS at its site. She added that Mountaineer may have an advantage with respect to GHG PSD permitting because of an ability to upgrade its existing units due to the existing CCS pilot project at the facility. Ms. Armstrong further explained that if Mountaineer makes any major modifications which would increase the site's GHG emissions by more than 75,000 tons $CO_2$, then it will already have CCS installed to treat and offset those emissions. Armstrong stated that it is not reasonable for Indiana ratepayers to support a project which may provide economic development opportunities and benefits to another state.

Finally, Ms. Armstrong reasoned that if the Commission allows I&M to include the CCS FEED Study costs in rates and the project is successful, I&M's ratepayers would have paid for a project without having access to the benefit of any carbon credits or allowances that may arise from the project. Armstrong recommended that if the Commission decides to allow I&M to recover the Mountaineer CCS FEED Study costs, then the Commission should require AEPSC to allocate a portion of any future $CO_2$ allowance revenues to I&M to pass back to its ratepayers. Ms. Armstrong noted that there are no cap-and-trade requirements in place at the Federal or Indiana state level for $CO_2$ or GHG emissions at this time, but there have been several bills proposed in Congress in the past which would create a carbon cap and trade system. Ms. Armstrong indicated that she was not aware of a mechanism that is currently in place that would allow I&M to receive $CO_2$ emissions allowances, but asserted that I&M and ratepayers should receive some of the allowance benefits from the Mountaineer CCS system if it funds any of the costs associated with its development.

As a result of Ms. Armstrong's recommendations, OUCC Witness Eckert adjusted the Company's O&M expense to remove the proposed adjustment of $805,500 ("Total Company"). Eckert Direct, at 35; Schedule MDE-5, p. 8. Mr. Eckert also disagreed with Petitioner's proposed two-year amortization period for the FEED Study adjustment. If the Commission were to accept I&M's adjustment, Mr. Eckert recommended amortizing the expense over the expected life of the rates. Eckert Direct, at 35.

(c) IG Case-in-Chief. IG Witness James T. Selecky also opposed the inclusion of the CCS FEED Study costs in I&M's revenue requirement based on his assumption that much of the study will be specifically geared toward the Mountaineer plant since it involves a test project at that plant. He stated that he is unaware of any plans to install any type of CCS facility at the Rockport Plant. Further, he testified that it appears I&M is seeking cost recovery simply because of a ruling of the WVPSC denying APCo's requested recovery of the Mountaineer CCS costs. He opined that because I&M did not seek prior approval from this Commission to participate in the FEED study, I&M's ratepayers should not be expected to pay for the costs of that study. Mr. Selecky recommended a reduction to total Company O&M expense of $805,500. Selecky, at 29-30.

(d) SDI Case-in-Chief. SDI Witness Ralph C. Smith provided testimony opposing I&M's O&M expense adjustment for the CCS FEED Study, stating that I&M has not shown how its ratepayers have or will benefit from the study. Mr. Smith described the VSCC decision with respect to recovery of the FEED Study costs and concluded that the same or similar factors and concerns that caused the VSCC to reject APCo's requested recovery of FEED Study costs from Virginia ratepayers would be applicable to I&M's request. Mr. Smith recommended removal of the FEED Study costs. He recommended that I&M's request for a regulatory asset and amortization of FEED Study costs over two years also be rejected. Smith, at 27-28.

(e) I&M's Rebuttal Testimony. Mr. Chodak argued that the costs of research and development are directed at minimizing environmental effects of coal, and are therefore appropriately included in rates. He referred to Indiana statutes and rules as authorizing recovery of R&D by utilities, and said that the CCS FEED study is directly transferable to Rockport because it is the same design as the Mountaineer plant. He said that the study positions I&M to use more Indiana coal and provide low cost generation, and that I&M customers would only bear part of the cost.

Mr. Chodak said that the OUCC had not shown that I&M was required either to seek approval to incur the FEED Study cost or have the Commission review the expense, because I&M is not seeking ratemaking recognition outside a general rate case. He also said that I&M gave the information to all other parties on November 7, 2011, and that the parties have had enough time to review the information.

Mr. Chodak admitted that additional work would have to be done to determine whether geological sequestration would work at Rockport and identify transportation to the site, but he argued that the R&D is necessary. He again stated that the Commission had previously approved FEED Study costs in Duke's Cause No. 43114 IGCC 1, and that the Commission should include the amount in I&M's rates.

(f) Commission Discussion and Findings.

The main issue that the Commission must resolve in this case regarding the recovery of coal-related research and development costs is whether research and development projects conducted on facilities or assets located out of the state and not owned by the utility in question can be recovered pursuant to I.C. § 8-1-2-6.1(c)(1) and 170 I.A.C. 4-6-17. In this case, I&M seeks to recover R&D expenses for a project located two states away which is not included in I&M's rate base and therefore not appropriately part of determining the utility's cost of service. In order to determine whether or not this is permissible under the special ratemaking treatment offered under the Utility Generation and Clean Coal Technology Statute, we turn to the language of the statute itself.

I&M directs our attention to Cause No. 43114 IGCC 1, Duke Energy Indiana's Edwardsport project, to demonstrate that the company has complied with the requirements for receiving cost recovery of research and development ("R&D") costs under I.C. § 8-1-2-6.1(c)(1). However, we disagree with Petitioner that this situation mirrors the issues that arise in 43114 IGCC 1. Duke Energy Indiana's R&D expenses for its carbon capture FEED study were related to a facility that is located in Indiana that will serve DEI's customers.

We note the language of I.C. 8-1-8.7-3(c) that "[a] public utility is not required to obtain a certificate under this chapter for a clean coal technology project that constitutes a research and development project that may be expensed under I.C. 8-1-2-6.1." However, cross-referencing back to that section, we note that "[t]he commission shall establish guidelines for determining recoverable expenses." I.C. § 8-1-2-6.1(e). Therefore, a utility's ability to recover such R&D costs is not unlimited, and falls within the area of the Commission's ratemaking expertise.

From the original language of the statute, it appears to us that the Indiana Legislature intended to promote economic development opportunities within the state, particularly for the Indiana coal industry. Newer additions to the statute also show that legislature intends to develop a robust and diverse portfolio of energy production and generating capacity to support Indiana's growing economy and to create additional jobs in Indiana, including promoting the use of Illinois Basin Coal. We cannot find a case where a utility has sought research and development expenses on a project located outside of Indiana.

While we acknowledge that carbon capture and sequestration studies to minimize the environmental impact of coal are necessary to ensure the continued future reliability of electric service to Indiana's consumers, we must also consider the site-specific nature of the study that I&M requests cost recovery of in this case. Upon reviewing the CCS FEED Study Project Plan and status reports presented in OUCC Attachment CMA-2, we agree with the OUCC that the activities conducted by AEP in this study are too location-specific to necessarily translate to any of I&M's coal-fired facilities. In addition, the "potential" application of any findings to Rockport, or any other I&M facility in Indiana, are remote and uncertain, at best. Clear geographical differences between West Virginia and Indiana call into question the transferability of the Mountaineer CCS FEED Study to an Indiana generating facility.

We are compelled to find that I&M cannot recover the costs of the Mountaineer CCS FEED study in rates. This is mandated by I.C.§ 8-1-2-4, which requires that a utility's rates be reasonable and just. The Mountaineer costs are unconnected to service rendered to I&M's customers, and therefore are not recoverable through rates. *Ind. Gas Co., Inc. v. Office of Util. Consumer Counselor,* 675 N.E.2d 739, 743 (Ind. App. 1997), *trans. den.,* 690 N.E.2d 1180. ("*Indiana Gas*") In addition, while "the utility may incur any amount of operating expenses it chooses, the Commission is invested with broad discretion to disallow for rate-making purposes any excessive or imprudent expenditures." *City of Evansville v. S. Ind. Gas & Elec. Co.,* 167 Ind. App. 472, 339 N.E.2d 562, 569 (Ind. App. 1975). In this case, we do not make findings regarding the prudence of APCo. in its pursuit of the CCS FEED study, but we do find it excessive to ask I&M ratepayers to be asked to bear the costs when no benefit will accrue to them.

Rates are based on service, and service contains a number of elements. *Indiana Gas*, 675 N.E.2d at 743. Our supreme court said it well regarding NIPSCO's request to recover costs related to the abandoned Bailly nuclear project.

> Any allowable operating expense must have a connection to the service rendered before it can be recovered through retail rates. See I.C. 8-1-2-4....The definition of service in I.C. § 8-1-2-1 restricts the scope of includable property to that property which performs and furnishes, i.e. producing property or "used and useful" property.... I.C. § 8-1-2-1 [and] I.C. § 8-1-2-4 protect[] consumers from having to pay for service not received...
>
> [W]e have been unable to conceive of a situation of our own in which the consumers could be required to replenish lost capital which had never become "used and useful" property or, in other words, be required to act in aid and support of the utility as an insurer of the investor's risk, unless consumers received an interest in return which provided an opportunity to earn a return on the capital supplied.
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> *Citizens Action Coal. v. N. Ind. Pub. Serv. Co.,* 485 N.E.2d 610, 614-15 (Ind. 1985), *cert. denied,* 476 U.S. 1137, 90 L.Ed. 2d 687, 106 S. Ct. 2239 (1986) (citation omitted).

This is equally applicable to I&M's requested recovery of the Mountaineer CCS FEED costs. We accepted Duke's request regarding their CCS FEED study costs in part because they related to a facility to be built in Indiana. The same cannot be said for the Mountaineer expenses. There is no relation to service provided to I&M's ratepayers, and any projected connection – namely, the possible application to Rockport or another I&M facility – is remote and without the kind of certainty required to establish rates.

Therefore, we find that the Mountaineer CCS FEED Study costs do not qualify as "research and development costs" under I.C.§ 8-1-2-6.1(c) and 170 I.A.C. 4-6-1(m), and are therefore not entitled to the cost recovery treatment specified in 170 I.A.C. 4-6-17. I&M's Operation and Maintenance Adjustment No. 39 is hereby denied.

(2) Dry Cask Canisters, including Storage.

(a) I&M Case-in-Chief. I&M Witness Carlson explained the Dry Cask Storage process and major components and testified that the Dry Cask Storage Project provides spent nuclear fuel dry storage capacity at the Cook Plant at an Independent Spent Fuel Storage Installation ("ISFSI"). Carlson Direct, at 14-15. He also explained that if additional fuel storage space were not made available, the Spent Fuel Pool ("SFP") would become full and the ability to offload spent fuel from the reactor to the SFP would be lost. *Id.* at 14. If the spent fuel cannot be removed from the reactor due to a loss of space in the SFP, new fuel cannot be loaded into the reactor and would require a shutdown of both units in approximately 2015. He testified that, by investing in the Dry Cask Storage Project, operations are able to be extended indefinitely, at least from a nuclear fuel perspective. *Id.* at 15. Mr. Carlson testified that the first loading campaign is scheduled to occur in 2012 during which 16 casks will be loaded with a total of 512 fuel assemblies (32 per cask) and 4 placed at the ISFSI. He also explained that, due to the complexity of dry cask storage, the project began 5 years in advance of this loading campaign. *Id.* at 16.

Mr. Carlson testified that the dry cask work included in the Company's Rate Base Adjustment No. 4 shown on Petitioner's Exhibit A-6 is comprised of many activities, including design and construction of the ISFSI; multiple engineering analyses and product reviews; labor and field services; construction and project management; and procurement of the dry cask transportation vehicle. He stated that this work was performed to ensure uninterrupted operation and to allow customers to retain access to low cost, essentially emission-free, and reliable electricity. *Id.*

I&M Witness Brubaker adjusted test year O&M expense to increase I&M's operating expenses by $259,132 to amortize the cost of dry cask canisters. Brubaker Direct, at 19. I&M Witness Carlson explained that the initial dry cask canister cost is $1,166,095 and is based on the number of spent nuclear fuel assemblies needing to be placed into dry cask storage as new fuel assemblies for refueling outages arrive at Cook. Carlson Direct, at 16. He stated that the amortization of the initial canister cost will take 54 months and will align with the three 18-month cycles in which nuclear fuel burns. *Id.* at 16-17.

Mr. Carlson stated that the Cook Plant will be receiving new fuel assemblies for the Unit 1 refueling outage in Fall 2011. He also explained that this shipment of fuel will put Cook in a position of being beyond the capacity of the Spent Fuel Pool, if both cores were required to be unloaded. Carlson Direct, at 17; Brubaker Direct, at 19. Mr. Brubaker explained I&M will begin expensing the cost of the canisters as fuel is consumed over the 54 month burn cycle using a cost per fuel assembly based on the cost of canisters to be used in the first haul campaign. As new fuel assemblies are loaded in the future, the calculated canister cost per fuel assembly will be amortized over each respective 54 month burn cycle. Brubaker Direct, at 19. Mr. Brubaker noted that if this adjustment was not made, I&M's test year operating expenses would be understated since there is no canister expense recorded in the test year. *Id.*

(b) OUCC Case-in-Chief. OUCC Witness Michael D. Eckert recommended that the Commission deny Petitioner's request to recover the amortized portion of the cost of the initial canister (total company $259,132/Indiana jurisdictional $164,518) through rates and to eliminate $1,775,040 in total company expense and $1,147,655 in Indiana jurisdictional expense. Eckert Direct, at 30.

Mr. Eckert stated that he did not agree with the recovery of the initial costs of the dry cask storage for two reasons. First, they represent a one-time project and are non-recurring, and second I&M received $14,125,864 from the DOE due to a settlement related to Yucca Mountain. *Id.* at 29-30. I&M entered into a settlement agreement with the U.S. Department of Energy ("DOE") regarding the government's decision to abandon development of a repository at Yucca Mountain. I&M has also requested an additional $20.9 million from the DOE for other expenses it has incurred. *Id.*

Mr. Eckert recommended that the Commission eliminate $1,775,040 in total company dry cask storage expenses ($1,147,655 Indiana jurisdictional) from operation and maintenance expense because it is a one-time non-recurring expense. *Id.* at 29. Mr. Eckert also testified that I&M conceded in response to OUCC Data Requests 37-5 and 37-6 that the project is a one-time project and that Petitioner did not provide the date the last such project was performed or the date additional such projects will be performed in the future. *Id.*

(c) I&M Rebuttal. On rebuttal, I&M Witness Scott M. Krawec argued that Mr. Eckert's assessment that the cost of the initial dry cask canisters were a one-time project and non-recurring was not accurate. Krawec Rebuttal, at 7. He speculated that the Cook Plant will shut down unless the storage of spent nuclear fuel in dry casks occurs as a regular activity (*i.e.*, loading campaigns). He said that as the Dry Cask Storage Project was performed to ready the plant for the loading campaigns, the dry cask canisters for the initial loading campaign were procured as part of this project and accordingly, are properly amortized as O&M expenses in accordance with FERC accounting guidelines. *Id.* at 7-8.

Mr. Krawec stated that the initial dry cask loading campaign will occur in 2012 and that additional dry casks will be loaded with spent nuclear fuel in subsequent loading campaigns, which will occur approximately every 3 years. *Id.* at 8. He said this activity is and will continue to be required until a permanent storage alternative becomes available. He also stated that the Cook Plant will continue to procure dry cask canisters for these loading campaigns throughout the remaining license periods of the units, and these purchases will be recorded initially to Account 165, Prepayments, and costs subsequently amortized to O&M expenses. He said that due to the continuing dry cask loading campaigns going forward, this recurring amortization expense is appropriate for inclusion in I&M's revenue requirement. *Id.*

In response to Mr. Eckert's argument that the dry cask storage canister expense should be entirely removed because of the settlement with the Department of Energy ("DOE"), Mr. Krawec indicated the Company has reached agreement on certain costs related to Dry Cask Storage, and some of those payments from the DOE have included reimbursement for canister costs. He said I&M has an investment in canisters that has not been recovered from the DOE and I&M continues to record a monthly expense related to the cost of canisters. *Id.* Mr. Krawec said that Mr. Eckert appears to believe that the future recovery of all of I&M's current and future investment in spent fuel storage canisters from the DOE is fixed and known. *Id.* at 8-9. Mr. Krawec said that there is no assurance that such recovery will occur. He also said that, as shown on Petitioner's Rebuttal Exhibit A-R5, O&M Adjustment R32, I&M has reduced the Total Company canister cost amortization from $259,132 to $177,372 to reflect the effect of the DOE reimbursement. *Id.* at 9.

Mr. Krawec discussed Mr. Eckert's proposal to eliminate $1,775,040 in total company and $1,147,665 in jurisdictional expense related to the dry cask storage project. Mr. Krawec said that the Company's original response to OUCC DR 37-1 and 37-2 had reported this expenditure as an "O&M" cost, but as shown on Petitioner's Exhibit SMK-R2, the Company has provided a supplemental response to OUCC DR 37-1 and 37-2 indicating that there were no O&M expenses included in the test year for the dry cask storage project. He indicated that dry cask canister costs will be amortized to O&M in the future, they were not charged to an O&M expense account during the test year. *Id.* at 10. Mr. Krawec stated that these costs were instead charged to FERC Account 165, Prepayments, which is a balance sheet account. Krawec Rebuttal, at 9-10. Specifically, I&M charged Account 1650022 for prepayments associated with canisters used to store Spent Nuclear Fuel ("SNF") that will be placed in dry cask storage. Amounts charged to Account 1650022 are not included in the Company's rate base or cost of service. Mr. Krawec suggested that it is inappropriate to make an adjustment to eliminate $1,775,040 (Total Company) and $1,147,665 (IN Jurisdictional) for dry cask storage expenditures from O&M

expense in the test year because these specific dry cask storage expenditures were not recorded to O&M expense in the test year. *Id.*

(d) Commission Discussion and Findings. The parties do not dispute the need for dry cask storage to allow for the safe handling of spent nuclear fuel and future refueling. However, the evidence shows a dispute among the parties as to how much of the costs are one-time non-recurring costs and how much should be reimbursed by DOE settlements related to Yucca Mountain. This Commission is persuaded that the need for dry cask storage appears to arise out of the absence of promised long-term disposal options, and that DOE settlement money should fund these costs. In the absence of a more complete record on the extent to which the costs are one-time non-recurring in nature, and in the interest of encouraging Petitioner to seek DOE settlement compensation for such expenses to the fullest extent possible, the Commission finds that it should deny Petitioner's request to recover the amortized portion of the cost of the initial canister (total company $259,132/Indiana jurisdictional $164,518) through rates and eliminate $1,775,040 in total company expense and $1,147,655 in Indiana jurisdictional expenses as recommended by OUCC Witness Eckert.

(3) NRC Fees.

(a) I&M Case-in-Chief. I&M Witness Carlson sponsored O&M Expense Adjustment No. 33 of Petitioner's Exhibit A-5, which increased Nuclear O&M expense by $955,907 on an Indiana jurisdictional basis. He explained that activities at the Cook Plant are governed by Nuclear Regulatory Commission ("NRC") regulations and I&M is assessed a fee to fund the cost of NRC regulation. During the course of plant operation, Mr. Carlson testified, the NRC regulations require activities that must be implemented in response to a number of variables, including external items such as operating events at other nuclear plants, new rule making, technology enhancements, as well as internal items. He stated the increase in O&M reflects the amount for NRC-mandated fees that I&M will incur for performing such activities and is based on the amounts published in the Federal Register. Carlson Direct, at 17-18.

(b) OUCC Case-in-Chief. OUCC Witness Eckert noted that I&M reflected NRC 2011 fiscal year hourly rate of $273 in its calculation of NRC Inspections and Reviews expense. He revised the pro forma level of NRC fees included in regulatory commission expense to incorporate the FY 2012 fee schedule published on March 15, 2012, which reflected an actual hourly rate ($274). Eckert, at 24. Mr. Eckert also recalculated the pro forma annual expense for NRC annual reviews using the actual test year bills received by Petitioner from the NRC. Mr. Eckert recommended a reduction of $1,342,259 in total company expense ($867,840 in Indiana Jurisdictional expense) for NRC annual fees, including inspection and review fees. *Id.*

(c) I&M Rebuttal. I&M Witness Brubaker testified on rebuttal that Mr. Eckert accurately represented the amount for NRC annual fees by using the actual amounts from invoices provided in discovery, but suggested Mr. Eckert incorrectly used an estimate for the hourly inspection and review fees. Brubaker Rebuttal, at 2. He suggested Mr. Eckert should have summed the amounts shown on the invoices received by I&M during the twelve months following the end of the test year. Using that methodology, the total annual hourly inspection and fee amount is $1,969,141. *Id.* at 2-3. Mr. Brubaker said the $955,907 increase proposed for O&M Expense Adjustment No. 33 should now be a reduction to test year expenses in the amount of $298,868. This is a $1,254,775 (Total Company) reduction to I&M's filed case instead of a $1,342,259 (Total Company) reduction recommended by Mr. Eckert. Mr. Brubaker stated the change reflects actual amounts from April 2011 through March 2012 for the annual inspection and review fee component of the total NRC fees. *Id.* at 3.

(d) Commission Discussion and Findings. Petitioner and the OUCC generally agree that NRC fee expense should be based on actual amounts from April 2011 through March 2012 for the annual inspection and review fee component of total NRC fees. We approve the corrected adjustment reflected in Petitioner's Exhibit A-R5 O&M Adjustment R33.

(4) Major Storm Expense.

(a) I&M Case-in-Chief. I&M Witness J. Edward Ehler testified in support of I&M's proposed adjustment to the test year to increase distribution O&M expense by approximately $2.3 million to reflect a three-year average of major storm O&M expense (using the three-year period ending March 31, 2011). Mr. Ehler suggested the average more accurately represented the normalized level of major outage restoration expenses. Ehler Direct, at 2-3; Krawec Direct, at 17 (Revised); O&M Expense Adjustment No. 34 of Petitioner's Exhibit A-5.

Mr. Ehler testified as to the reasonableness of the storm restoration level proposed by discussing the random and unpredictable nature of storms, including the fact that storms can vary in size, significance and impact, thus creating volatility in the level of related expenses year to year. Ehler Direct, at 5. Mr. Ehler said during 2011 a single major storm cost approximately $1.2 million, an amount representing over half of the approximately $2.3 million adjustment. *Id.* He argued this information, coupled with the evidence showing that test year major storm damage restoration amount is significantly less than the $6.1 million average major storm cost, demonstrates the reasonableness of the proposed level. *Id.*

Mr. Ehler said the Commission has accepted I&M's use of a three-year amortization period in a previous I&M rate case. Ehler Direct, at 4. Mr. Ehler said using a consistent approach for determining major storm expense for ratemaking purposes is reasonable and appropriate because it recognizes that major storms are experienced in the normal course of events.

(b) OUCC Position. OUCC Witness Michael D. Eckert testified in opposition to Petitioner's request for pro forma storm damage expense of $6.2 million. Eckert, at 19 – 23. Mr. Eckert explained that I&M developed its major storm damage expense by separately adjusting both transmission and distribution storm-related costs for the test year to reflect a three-year historical average level of costs based on a three-year average for the years April 2008 through March 2011. Mr. Eckert noted that according to I&M Witness Mr. J. Edward Ehler, "This adjustment is necessary to reflect in I&M's cost of service a representative three-year average of major storm O&M expenses that more accurately represents a normalized level of expense.[7]" *Id.* at 19.

Mr. Eckert disagreed with Petitioner's normalized storm costs. Although he agreed it is reasonable to normalize storm-related costs, he stated that the three-year period Petitioner used in this Cause is not representative of normal Major Storm Expense. Mr. Eckert explained that the three-year period Petitioner used includes two of the three highest years for Major Storm Expense during the last six years. (Petitioner used periods ending March 31 in its calculation. Therefore, Mr. Eckert also looked at 12-month periods ending on March 31.) Mr. Eckert noted that in December 2008, I&M experienced a severe storm that caused significant customer outages and resulted in Petitioner incurring significant costs. The storm costs between April 2008 and March 2009 totaled $13,519,543. Eckert, at 20. Of that total, $11,174,157 was the result of the December 2008 storm. Mr. Eckert included in his testimony a table that showed those storm costs were significantly higher than storm costs in any other recent year. Thus, storm-related costs for the period ending March 31, 2009, were more than three times those in the test year and significantly more than the other five years Mr. Eckert reviewed. Mr. Eckert stated that a three-year average that includes the period ending March 31, 2009 does not produce a representative result and overstates the costs that Petitioner would expect to incur in a typical or normal year. *Id.* at 21.

Mr. Eckert disagreed with Mr. Ehler's assertion that a three year average is the best number of years to use to estimate normalized major storm expense. Mr. Eckert stated that three years are a relatively small number of historical years to use, which will create a larger variance in the average depending on which years are used. (Mr. Eckert included in his testimony historical storm costs for the twelve months ending March 31 in 2007 ($1,286,762), 2008 ($871,671), 2009 ($13,519,543), 2010 ($996,430), 2011 ($4,391,227), and 2012 ($4,602,039).) Eckert, at 21.

Mr. Eckert noted that in the case of the three years Petitioner proposes using, the average for major storm expense ($6.3 million) is significantly higher than any of the other potential formulas (4-year - $4,944,718, 5-year - $4,213,127, or 6-year average – $4,277,945). He then noted that a three year average based on the three most recent years (April 2009 through March 2012) would result in an average ($3.3 million), which is lower than any of the same alternative methodologies. Eckert, at 22. Mr. Eckert noted that Petitioner's methodology does not explain why a three year average using the three most recent years of data we have would not be just as valid as the three years Petitioner originally proposed in its case-in-chief. Mr. Eckert stated that in this case, the three-year average ending March 31, 2011 produces an unreasonably high estimate, while the three-year average ending March 31, 2012 produces an unreasonably low estimate. *Id.*

Mr. Eckert stated that normalized storm costs would be more representative if based on the average level of expenses for the five-year period April 2006 through March 2011. As shown on Mr. Eckert's Schedule MDE - 5, page 7, this adjustment results in total normalized annual storm expense of $4,213,127. Mr. Eckert determined the distribution amount of storm costs to be $4,047,529, which is a reduction of $2,038,787 to distribution storm costs when compared to I&M's request of $6,086,316. Mr. Eckert noted that distribution storm costs are

[7] See Petitioner's Witness J. Edward Ehler's testimony page 2, lines 19-22.

directly assigned to the Indiana jurisdiction. For transmission, Mr. Eckert determined average annual storm costs to be $165,598, as shown on Schedule MDE - 5, page 7. He explained this represents a reduction of $49,731 on a total company basis and $32,154 on an Indiana jurisdictional basis compared to I&M's claims. Eckert, at 22.

Mr. Eckert noted that with respect to its calculation of transmission plant, Petitioner inadvertently subtracted its pro forma expense amount from its test year expense and calculated an increase to Major Storm Expense of $210,659. Mr. Eckert explained that Petitioner should have subtracted its test year expense amount from its pro forma proposed expense, which would have resulted in a decrease to Major Storm Expense of $210,659. Eckert, at 23.

Mr. Eckert noted the actual test year major storm expense was $4,391,227, which compares to the five year average of $4,213,127. Also, as discussed in more detail by OUCC Witness Mr. Anthony A. Alvarez, Mr. Eckert noted I&M experienced major storms outages in its service area that caused significant customer outages during the test year. Mr. Eckert noted the significant amount of storm activity during the test year, and stated this also supports rejection of I&M's proposed upward adjustment to actual test year major storm expense. *Id.*

Mr. Anthony A. Alvarez, Utility Analyst with the OUCC, presented testimony to introduce and provide the analysis and calculation of I&M's customer service outage hours and kilowatt-hours losses due to Major Event Days ("MEDs"). His analysis and calculation supported OUCC Witness Mr. Michael D. Eckert's adjustment to major storm expense. Mr. Alvarez also addressed the need for I&M to maintain complete records of I&M's outage reports to the Commission.

Mr. Alvarez quoted the Commission's definition of the term "major event" as being "storms or weather events that are more destructive than normal storm patterns," to explain its relevance to a major storm. He testified that Commission Rules require the utility to define major event as used for reporting purposes. *See* 170 Ind. Admin. Code 4-1-23(e)(a). Mr. Alvarez testified that utilities calculate their reliability indices with and without major events. He stated that by including major events in one set of the utility's reliability indices, the utility can point out the impact of storms in their service area. He stated that reliability indices "without major events" show the utility's operating performance under normal conditions.

Mr. Alvarez pointed out that I&M adopted the IEEE Standard 1366-2003 methodology of determining major events for Indiana reliability reporting on March 1, 2005. He stated that the IEEE Standard 1366-2003 introduces the concept of Major Event Days ("MEDs") and uses the "2.5 beta methodology" in defining major event. He explained that the IEEE Standard 1366-2003, 2.5 beta method uses five (5) sequential years of historical SAIDI (System Average Interruption Duration Index) data in calculating the utility's MED threshold value, $T_{MED}$. Mr. Alvarez testified that an MED is a day in which the system SAIDI exceeds the MED threshold value, $T_{MED}$.

Mr. Alvarez testified that the SAIDI reliability performance index was chosen because it is size independent and provides the best indicator of system stresses beyond what the system is designed, built and staffed to withstand. He stated that SAIDI measures the duration of a service interruption for the average customer for a specified period of time. He identified other reliability performance indices used by utilities, such as: SAIFI (System Average Interruption Frequency Index) which measures how many sustained service interruptions a customer experiences over a specified period of time, and CAIDI (Customer Average Interruption Duration Index) which measures the average time the utility needed to restore service after a sustained service interruption.

Mr. Alvarez explained how the IOUs (independently-owned utilities) in Indiana defined major events. He testified that three (3) of the Indiana electric IOUs (Duke Energy Indiana, I&M, and NIPSCO) have adopted the IEEE Standard 1366-2003 to define a major event. Vectren South Electric and Indianapolis Power & Light Company each have "internal" definitions for a major event. Mr. Alvarez testified that all five (5) Indiana IOUs used SAIFI, SAIDI and CAIDI reliability performance indices, which are the most commonly used indices to report to state public utility commissions nationwide. He stated that thirty-five (35) state-PUCs and the District of Columbia require routine reporting of reliability event information.

Mr. Alvarez's Table 2.0 illustrated how MEDs affect I&M's reliability performance indices. His table showed I&M's annual SAIDI and SAIFI from 2006 to 2011, and the percent (%) variances between each index "with MED" and "without MED." His calculations identified I&M's high SAIDI and SAIFI variance results for the particular years 2008 and 2010, correlated to the relatively higher number of MEDs during 2008 and 2010. This increased I&M's SAIDI (2008: 708.33%, and 2010: 253.13%), and SAIFI (2008: 45.54%, and 2010: 32.43%). He testified that the higher number of MEDs directly affected SAIDI with prolonged power outages, and SAIFI with increased overall interruption frequency.

Mr. Alvarez testified that there were six (6) MEDs reported in I&M's jurisdictional service area during the test year. He quantified the effect of MEDs by calculating the outage kilowatt hour losses attributed to MEDs. He testified that the major storm that triggered the multiple MEDs for June 18, 19, and 20, 2010 was extensive and affected approximately 52,000 customers, and lasted approximately 63 hours. He stated that the events that triggered the MEDS during the test year ended March 31, 2011, accumulated approximately 2,259,900 of outage customer-hour loss that translated to approximately 4,459,425 of outage kWh loss. Mr. Alvarez's table detailed the customer-hour and kWh losses in the test year due to MEDs; one major storm triggered multiple MEDs (3), and was attributed 80.43% of the total outage kilowatt-hour losses due to MEDs.

He also noted that I&M did not provide the required set of outage reports corresponding to the July 23, 2010 MED date I&M reported during the test year. Mr. Alvarez testified that 170 I.A.C. 4-1-23(e) requires I&M to report its electric reliability measures, and 170 I.A.C. 4-1-23(b) requires I&M to submit outage reports to the Commission. He used I&M's reliability and outage reports to the Commission from 2006 to 2011 to calculate the customer-hour and kilowatt-hour losses related to major storms. He explained the analysis and calculations of the total outage customer-hour and kilowatt-hour losses that he used to quantify the effect of, and attribute to MEDs.

Mr. Alvarez explained that the "Initial Report" for each outage served as the starting point of his calculations. He tabulated the number of customers without power, and the duration of the outage at each reporting interval as shown in his Attachment AAA-2. He explained that the Total Customer-Hour Loss attributed to MEDs is the product of the average customer counts and the calculated duration between each reporting interval. Mr. Alvarez testified that the Total Outage Kilowatt-Hour Loss attributed to MEDs is the product of the Total Customer-Hour Loss and the Hourly Usage Factor found in his Attachment AAA-3. Mr. Alvarez also calculated the total outage losses (customer-hour and kilowatt-hour losses) attributed to MEDs in other periods outside of the test year.

Mr. Alvarez's Table 5.0 showed the total outage losses (customer-hour and kilowatt-hour losses) attributed to the MEDs for periods ended from 2007 to 2011, including the test year. Mr. Alvarez showed that the period year 2009 and the test year have captured relatively higher number of MEDs compared to the other periods. He testified that the resultant outage losses (customer-hour and kilowatt-hour losses) for the period year 2009 and the test year, with relatively higher number of MEDs, were significantly larger than the rest of the other period years in the table. He added that this outcome is supported by his analysis of the increases in I&M's SAIDI and SAIFI due to higher number of MEDs.

Mr. Alvarez's analysis showed that 2009 and the test year have more than the average number of MEDs, and the total outage losses (customer-hour and kilowatt-hour losses attributed to the MEDs) were greater than the average outage losses of the other period years. He stated that the results of his analysis provided support to OUCC Witness Mr. Eckert's proposed pro forma major storm expense.

Mr. Alvarez addressed I&M's compliance with the Commission's outage reporting requirements. I&M is required to submit power outage reports to the Commission pursuant to 170 I.A.C. 4-1-23(b)(1). He stated that I&M is also required to provide "status update reports" in between the initial and the final outage reports. He stated that the OUCC found that I&M failed to file initial and final reports, and status update reports were missing required information such as the number of customers, the date and time such customers were affected by the outages. He testified that the OUCC requested the missing information, but was told by I&M that it was either unable to locate the missing outage reports in its records, or that "[n]o outage report exists that shows this amount of estimated number of customer affected."

Mr. Alvarez expressed the OUCC's concern regarding I&M's failure to maintain complete outage reports. Mr. Alvarez noted I&M's response to outage report inquiries that "as a matter of course, I&M provides Outage Reports to the Commission as required by 170 I.A.C. 4-1-23(b)(1)..."[h]owever, I&M was not able to locate any report in its records for these specific time periods." Mr. Alvarez also explained the OUCC's concern regarding the accuracy of critical information in the outage reports that I&M provided the Commission and the OUCC. Mr. Alvarez testified that through the discovery process, the OUCC established that I&M provided inaccurate critical information regarding different numbers of "customers affected" for the same date and time in the outage reports submitted to the Commission.

Mr. Alvarez recommended that I&M provide the Commission and the OUCC consistent outage report information, both in hard and electronic copies, and to submit such reports at regularly scheduled intervals, as required by the Commission Rules, to maintain complete, accurate, and reliable outage reports on a going forward basis.

(c) IG Position. Mr. Selecky opposed I&M's proposed increase in storm damage O&M expense of approximately $2.3 million and recommended that the Commission cap the level of storm damage O&M expense in the Company's revenue requirement at the five-year average, or $4.213 million. He testified that I&M's proposed three-year average for storm damage includes a significant storm damage cost for 2009 and should not be viewed as a representative value. Selecky Direct, at 28-29. Mr. Selecky also offered an alternative procedure in which the Commission would look at the last five years, remove the highest and lowest year and develop a three-year average from that data, which would result in storm damage expense of $2.225 million. *Id.*

(d) SDI Case-in-Chief. SDI Witness Ralph C. Smith did not object to I&M using a multi-year period as the basis for establishing a normal level of major storm expenses. He stated that looking at data for a fluctuating expense over a multi-year period is a reasonable way to establish a normal allowance for ratemaking purposes. Smith Direct, at 37. He did not agree that the three-year period used by I&M to calculate its adjustment is the best representation of a normal level for major storm expense for I&M. *Id.* In his cross-answering testimony, Mr. Smith supported the OUCC recommendation.

(e) I&M Rebuttal. Petitioner's witness Scott Krawec discussed the testimonies of OUCC witness Mr. Eckert, the Industrial Group's witness Mr. Selecky and Steel Dynamic's witness, Mr. Smith. Mr. Krawec noted that all those witnesses agreed major storm expenses should be normalized for the purposes of determining the appropriate expense level for inclusion in the Company's revenue requirement. Mr. Krawec said any disagreement centers on what period should be used to develop the average or normalized expense. Mr. Krawec said the forgoing witnesses recommend the Commission reject the time period I&M proposed in favor of a different time period to develop the average or normalized expense. Mr. Krawec said the OUCC and intervenors contend that the average major storm for the three-year expense level period selected by I&M is abnormally high and should therefore be rejected in favor of a longer period (i.e. five years). Mr. Krawec disagreed with Mr. Eckert's reasoning that a longer period would be "more representative." Mr. Krawec said the process of normalization ameliorates the impacts of an unusually high or low expense level and thus alleviates concerns that the test year expense might be an anomaly.

Mr. Krawec theorized I&M's three-year proposal is consistent with prior practices of the Company and stated I&M has consistently proposed a three-year average in its rate cases to determine the appropriate major storm2 expense. He said this methodology was accepted by the IURC in Cause No. 39314 where it reduced I&M's major storm expense. Mr. Krawec said in I&M's last rate case, Cause No. 43306, I&M proposed a three-year average for major storm expense, but agreed to a five-year average in the context of the give and take of settlement. Mr. Krawec suggested that the consistent use of the three-year average to normalize major storm expenses from rate case to rate case is fair and reasonable and alleviates concerns that the particular normalization period might be chosen, either by the Company or others, to skew the level of costs in the revenue requirement to achieve a particular result.

Mr. Krawec admitted I&M may not be able to predict when severe storms will hit, but that they do occur and are part of I&M's ongoing operations. Mr. Krawec suggested recent experience shows that I&M has experienced an extremely destructive storm, such as I&M

experienced in 2008, every three years. He said that prior to 2008, I&M experienced a January 2005 weather event in I&M's Muncie District that resulted in 87 percent of the district's customers losing power. Mr. Krawec said during the course of 2005, I&M's Indiana jurisdiction had over $15 million in O&M expense related to major storms. Based on those two events, Mr. Krawec theorized that a methodology utilizing five years or more to determine major storm costs is an inconsistent approach and may not be representative of I&M's true storm restoration costs.

(f) Commission Discussion and Findings. The OUCC used a five year average of the period April 1, 2006 through March 31, 2011 ($4,213,127) to show that I&M's test year ($4,391,227) is representative of its major storm expense.

Mr. Krawec as well as Mr. Ehler urged us to accept the premise that a three year average is the most representative average to establish pro forma major storm expense. Mr. Krawec notes this is consistent with I&M's practice of proposing a three year average in its rate cases. The only reason either witness provided that speaks to why a three year average is better than a five year average is Mr. Krawec's contention that recent experience shows that a particularly destructive storm happens every three years. Mr. Krawec gave as an example the storms of 2005 and 2008. (Mr. Krawec makes no mention of a particularly destructive storm since 2008, though the record includes data through March 31, 2012.) There is simply not the scientific evidence presented in this case to support such a premise.

I&M has not adequately or convincingly explained why a five year average should be considered less representative than a three year average. Mr. Krawec's rebuttal listed two reasons why we should embrace a three year average for normalized major storm expense. First, Mr. Krawec stated the very process of normalization ameliorates the impacts of an unusually high or low expense level and thus alleviates concerns that the test year expense might be an anomaly. This is not argument that favors a three year average over a five year average. In fact, a five year average should be more effective than a three year average in ameliorating the impacts of an unusually low or high expense level. Nothing illustrates this more effectively than the fact that the two three (3) year averages presented in this case represent the highest ($6.2 million) and lowest ($3.3 million) averages under consideration.

If we embrace Mr. Krawec's and Mr. Ehler's contention that a three year average is better than a five year average, we would need to confront the fact that the average of the most recent three years (April 1, 2009 through March 31, 2012) for which we have data indicate an average annual expense of $3.3 Million as Mr. Eckert pointed out in his testimony. Likewise, we would also note that a six year average includes two three year averages. If we accept I&M's assertion that "an extremely destructive storm" happens every three years, a six year average, which includes two three-year periods, as well as should in theory capture this phenomena just as well. Averaging the six most recent years, for which we have data presented in this case, indicates an average major storm expense of $4,277,945, which is only slightly higher than the five year average of $4,213,127 Mr. Eckert used and comparable to Petitioner's test year amount of $4,391,227.

Second, Mr. Krawec asserted that a methodology using five years or more to determine major storm costs is an inconsistent approach and may not be representative of I&M's true storm restoration costs. Mr. Krawec asserted that I&M's three-year proposal is consistent with prior practices of the Company and stated that I&M has consistently proposed a three-year average in its rate cases to determine the appropriate major storm expense. For instance, he asserts this methodology was accepted by the IURC in Cause No. 39314 where it reduced I&M's major storm expense. Mr. Krawec explained that in I&M's last rate case, Cause No. 43306, I&M proposed a three-year average for major storm expense, but agreed to a five-year average in the context of the give and take of settlement. Mr. Krawec asserted that the consistent use of the three-year average to normalize major storm expenses from rate case to rate case is fair and reasonable and alleviates concerns that the particular normalization period might be chosen, either by the Company or others, to skew the level of costs in the revenue requirement to achieve a particular result.

Our task as it relates to this issue is to determine an amount to embed in rates as a *pro forma* revenue requirement for I&M's major storm damage expense. In so doing, we are considering a methodology that will result in an amount we may consider representative of I&M's ongoing major storm expense for the period following this rate order. That I&M may have consistently proposed a three year average to estimate this expense does not in any way bind us to adopting a three year average to set pro forma major storm damage expense. If we were concerned with consistency above all other concerns, we would note that a five year average of major storm expense is consistent with our last order. But our focus is not on consistency but on finding a methodology that will yield a representative level of major storm expense. As we have noted above, the most recent three year averages produce dollar amounts that can be considered outliers. Conversely, the averages that consist of five years tend to produce numbers that are not extremely high or extremely low. We do not agree that we can base our decision on the premise asserted by Petitioner that we can expect an extremely destructive storm, such as I&M experienced in 2008, every three years. As Petitioner has also noted, severe storm-related costs are volatile and incurred at somewhat irregular intervals, they also defy attempts to predict their occurrence. Krawec Rebuttal at 38-39.

It is well understood that an average that consists of more years tends to produce a number that in the long run should be less likely to overstate or understate a cost. Accordingly, we reject Petitioner's assertion that averaging longer periods yields a less reliable and less representative result. Indeed, a longer period such as five or six years lessens the effect of including years with an unusually low or high amount of major storm expense as would happen if we used a three year average.

Petitioner's assertion that a three year average for major storm expense is the most representative is simply unfounded and illogical. As such, we agree with the OUCC that a five year average is a better indicator and more representative of average major storm expense on which to base I&M's pro forma revenue requirement. In light of the forgoing, we find that the pro forma revenue requirement for major storm damage expense shall be $4,213,127, which is based on the average level of expenses for the five-year period April 1, 2006 through March 31 2011.

We also note the OUCC's appropriate concern regarding I&M's retention of accurate storm outage reports. The requirements of 170 I.A.C. 4-1-23(b)(1) are not an afterthought, but are meant to guarantee that the Commission has accurate information regarding utilities' outages, the number of customers affected, and the length of time it takes to restore service. In light of

I&M's request for storm damage expense, it is imperative that I&M follow not only the spirit but the letter of the law and show that its storm response is timely and complete. We therefore agree with the OUCC that I&M should consistently file and *retain* outage reports, as set forth in our rules.

(5) Major Storm Restoration Reserve.

(a) I&M Case-in-Chief. Mr. Krawec sponsored I&M's request to create a Major Storm Damage Restoration Reserve (the "Reserve"). Mr. Krawec testified that I&M's test year storm damage O&M expense as adjusted, is approximately $6.2 million (Indiana Jurisdictional). Under I&M's proposal, implementation of new basic rates would include the proposed major-storm damage restoration reserve mechanism, and I&M would calculate monthly any over-recovery or under-recovery by comparing the current month proposed major-storm damage restoration reserve revenues collected in basic rates to the current month major-storm damage restoration expenses. Krawec Direct, at 17, Brubaker Direct, at 27-28. If the incurred O&M is less than the monthly amount reflected in the revenue requirement, the Company will record a regulatory liability in Account 254, Other Regulatory Liabilities, for any over-recovery related to its proposed Major Storm Damage Reserve. Krawec Direct, at 17, Brubaker Direct, at 26, 28. If the incurred O&M exceeds the monthly amount included in the revenue requirement, the Company will record a regulatory asset in Account 182.3, Other Regulatory Assets for any under-recovery. Krawec Direct, at 17-18, Brubaker Direct, at 26, 28. The cumulative regulatory liability or regulatory asset balance would be adjusted each month based on actual major storm damage O&M incurred versus the embedded amount. Krawec Direct, at 18.

In its next general rate case, I&M proposes to include an amortization in the cost of service developed for that case which will either reduce the cost of service for any over recovery or increase the cost of service for any under recovery at the end of the historical test period. In addition, I&M will propose an adjustment to the base level of the Indiana Major Storm Damage Restoration Reserve that reflects recent historical major storm damage levels. Krawec Direct, at 18, Brubaker Direct, at 28.

Mr. Brubaker said that generally accepted accounting principles ("GAAP") and in particular FASB ASC 980 (formerly SFAS No. 71, Accounting for the Effects of Certain Types of Regulation) requires deferral accounting when a regulatory commission requires future rates to be reduced to refund an over recovery and when a regulatory commission provides for the future recovery of incurred expenses or it is probable that a regulatory commission will provide for such future recovery of an incurred expense. Brubaker Direct, at 26-27. Therefore, in order to record regulatory liabilities or regulatory assets and perform regulatory deferral over/under true-up accounting, it must be probable that the resultant regulatory assets or regulatory liabilities will be recovered, or returned to customers, through future regulated rates. *Id.* at 27. He said the probability requirement will be satisfied if the Commission's Order provides for prospective rate adjustments in basic rates, either upward or downward, to recover from customers or return to customers the deferred under-recovered regulatory asset or over-recovered regulatory liability balances, respectively. *Id.* When that occurs, the regulator-created asset, or regulatory asset, must be recorded by deferring the incurred cost to be recovered in the future or the regulator-created liability, or regulatory liability, must be recorded by deferring the amount to be returned in the future. *Id.*

Mr. Brubaker said the FERC Uniform System of Accounts requires that regulatory assets and regulatory liabilities imposed on the utility by the ratemaking actions of regulatory agencies be included in Account 182.3, Other Regulatory Assets and Account 254, Other Regulatory Liabilities, respectively as I&M proposed.

(b) OUCC Case-in-Chief. OUCC Witness, Wes Blakley provided testimony opposing Petitioner's request for special ratemaking treatment for Major Storm Damage Expense. Mr. Blakley noted that Petitioner's proposal with respect to major storm damage expense is in two parts – a *pro forma* storm damage expense using a three (3) year average followed by the special regulatory treatment Petitioner calls the Major Storm damage Reserve. Mr. Blakley noted I&M calculated its pro forma storm damage expense by using a three (3) year average of actual storm damage costs from April 1, 2008 through March 31, 2011, which is the end of the test year. Petitioner's initial proposal for pro forma major storm damage expense was approximately $6.3 million, which included $6.087 million for distribution expense and $215,329 for transmission expense. Mr. Blakley noted that Mr. Krawec revised his testimony and reduced the *pro forma* expense for major storm damage down to $6.2 million. Mr. Blakley noted that the actual test year total for both distribution expense and transmission storm damage expense is $4.391 million. Blakley, at 3.

Mr. Blakley explained the mechanics of the proposed ratemaking treatment. He advised that if authorized by the Commission, I&M would establish the monthly storm amount by dividing the pro forma expense of $6.2 million, by 12 to derive a monthly base amount of $516,667, which I&M would use to record either a regulatory asset or a regulatory liability. Mr. Blakley explained that if expenditures in a given month in the storm account are above $516,667, I&M would record a regulatory asset equal to the difference. Blakley, at 3. If expenditures in a given month in the storm account are below $516,667, it would record a regulatory liability equal to the difference. Mr. Blakley explained that each month I&M would record a regulatory asset or liability depending on the monthly expenditures on storm damage. At the time of its next rate case, if the balance of this account reflects a regulatory asset, I&M would be permitted to amortize the balance as a charge to customers and recover it in future rates. If the account balance reflects a regulatory liability, I&M would amortize it as a credit to customers in future rates. Mr. Blakley added that I&M would also propose a pro forma storm expense amount to be included in base rates at the time of the next rate case. Blakley, at 4.

Mr. Blakley stated the term "reserve" does not accurately describe the relief Petitioner seeks. Mr. Blakley said the term "reserve" implies cash funds will be accumulated and set aside for a specific purpose, but this is not the case with I&M's request. He added that I&M is not requesting authority to accumulate and set aside funds to pay for major storm damage expenses. Nothing in rates will accumulate funds for a reserve amount to be used later for storm damage expenses. What I&M actually seeks is special accounting treatment attached to a single expense account. Blakley, at 4.

Mr. Blakley explained how the special accounting treatment would benefit I&M by noting the ability to create a regulatory asset for expenses that may go over a base amount creates a hedge for I&M in dealing with its major storm expense. That is, I&M would be protected from any storm damage expense caused by major storm events exceeding the monthly base amount of $516,667. He noted that this special accounting treatment would financially insulate I&M from the risks of major storms. Blakley, at 4. He added that the special accounting treatment would transfer that risk to the ratepayers. *Id.* at 4-5.

Mr. Blakley testified he has been a staff accountant with the OUCC for more than twenty years, but he does not recall a request for an operating expense that included special accounting treatment that essentially guaranteed recovery of an operating expense that exceeds a base amount. Blakley, at 5.

Mr. Blakley noted that I&M's proposed major storm expense could have a significant impact on ratepayers at the time of its next base rate case. Mr. Blakley explained that, unlike post-in-service AFUDC, for instance, in which the cost of a project and the interest rate are substantially known, the potential future cost to the ratepayers of the proposed regulatory asset is entirely open-ended and unknown. He explained that the cost does not depend on the cost of a project or an interest rate, but on what is often described as acts of God or acts of Nature. Under this proposed regulatory scheme, the best the ratepayers could hope for is an offset in rates of the major storm expense to be established in the next rate case. On the other hand, the potential size of the regulatory asset that could be created is unlimited. Blakley, at 5.

Mr. Blakley declared I&M's proposal ill-conceived. Mr. Blakley noted that under I&M's proposal, it is not clear who would be responsible for auditing its accounting for storm damage expenses and the accumulation of regulatory assets and liabilities. He noted that I&M will be in charge of the accounting month-by-month. He suggested that at its next rate case, I&M would present a regulatory asset or liability of unknown size. If this special treatment is approved by the Commission, then any party that seeks to challenge the future amount would have a very difficult task, which could require reviewing multiple years of monthly storm damage accounting. Blakley, at 5.

Mr. Blakley described the proposal as single issue ratemaking and explained that I&M requests to single out major storm expense for special accounting treatment that is set up to capture and defer any major storm expenses above the base amount that may occur between the time of the current rate case until its next rate case. This treatment proposed is without regard to other expense components or return components that may change during the same period. Blakley, at 6.

Mr. Blakley noted the Commission discussed the dangers of single issue ratemaking in the context of storm expense. He explained that in its final order in Cause No. 43743, issued October 19, 2011, the Commission discussed why such single issue ratemaking in the context of major storm expense is inappropriate:

> Because such risks cannot be adequately predicted at the time of a rate case, those risks are also considered in establishing a utility's return on equity. Furthermore, the fact that this one expense, i.e., storm damage, exceeds its base rate revenue requirement does not address whether the utility may have had other offsetting operating.

Mr. Blakley agreed there are other cases where the Commission has ruled on Major storm expense. Blakley, at 6. Mr. Blakley related that in a 1991 storm case, the Commission found that the electric utility was compensated for storm damage in two fashions, once in storm damage expense of approximately $2,000,000 and through the inclusion in rates of the opportunity to earn a reasonable return commensurate with the returns associated with investments containing similar risks. The Commission said that "We believe the return granted by this Commission in PSI's most recent rate case compensates it for the operational risk of severe weather."[8]

Mr. Blakley said that over the years, the Commission has had a thoughtful approach to handling storm damage expenses by electric utilities. Mr. Blakley noted that in doing so, the Commission's orders show that the Commission has strived to provide electric utilities with a reasonable level of pro forma operating expense. He added that the Commission recognizes that in some years the utility will under recover and in some years it will over recover on operating expenses for storm damage. Mr. Blakley stated that the operation of a utility involves risk and such risks are appropriately recognized in the utility's return on equity. Blakley, at 7.

Mr. Blakley said Petitioner's proposed special regulatory asset scheme does not represent an appropriate solution for unpredictable storm expense since it would make the ratepayers responsible for the risk of all major storm damage expense in excess of the amount approved in rates. He added that the entity that is in the best position to (1) respond to a given event or (2) take precautions against a given event should bear the consequences of the risk. Mr. Blakley stated that the ratepayers are not in a position to do either. As the owner and operator of its system, I&M should be appropriately incented to do both. Mr. Blakley added that to the extent I&M can take steps to reduce the operating expense caused by major storm damage, it is not unreasonable that it be permitted to enjoy the financial benefits of costs avoided through its prudence and diligence. Blakley, at 7. Mr. Blakley advised that under I&M's proposal, any operating expense caused by a major storm event would not be borne by I&M but would ultimately be borne by its ratepayers. Under this proposed scheme, costs avoided by I&M's prudence or diligence would only benefit I&M's ratepayers through a regulatory liability. Preservation of the integrity and reliability of I&M's transmission and distribution system is important. Mr. Blakley said that removal of existing and natural incentives that promote preservation of the system should be discouraged. *Id.* at 8.

Mr. Blakley added that even if I&M had no ability to avoid major storm damage expense, it does not make sense for its ratepayers to financially insulate I&M from major storm damage expense it incurs. I&M's proposal might better be described as ratepayer-supplied insurance for major storm damage expense. Mr. Blakley noted that I&M's ratepayers are not currently nor should they be required in the future to participate in the business of insuring I&M from storm damage expenses. *Id.*

Mr. Blakley stated that the long-established and accepted practice of providing a reasonable, pro forma amount of storm expense in base rates is reasonable. Mr. Blakley said that the *pro forma* amount can be calculated either using the test year, which may have some major storm activity, or if not, by using an average of years that include some major storm activity. He

[8] PSI Energy, Inc., Cause No. 39195 order, February 26, 1992, at page 10.

said this approach should provide adequate funds for storm expense into the future. Moreover, it will also preserve I&M's natural incentive to handle major storm damage expense with prudence and diligence. Accordingly, Mr. Blakley said that I&M's deferred accounting treatment or "reserve" proposal should be rejected. *Id.*

(c) IG Case-in-Chief. Mr. Selecky testified that the Commission should not approve I&M's proposal to create a Major Storm Damage Reserve and stated that, as a matter of policy, the Commission should limit the use of riders and tracking mechanisms because they shift regulatory risk from investors to customers. Selecky Direct, at 26. Mr. Selecky further testified that riders and tracking mechanisms undermine the Commission's ability to evaluate the sufficiency of a utility's rates in the context of a full rate proceeding, based on the totality of the utility's costs and revenues for a given test year. *Id.* Mr. Selecky opined that a policy that permits a utility to adjust its rates for individual cost or revenues items outside of a rate case shifts regulatory risk from utility investors to customers by providing investors a guaranteed recovery of specific cost and revenue adjustments in utility rates. *Id.* He added that this change in the Company's risk profile would occur without a corresponding reduction to its rate of return to recognize the reduced business risks faced by the utility. *Id.* at 26-27. Mr. Selecky testified that a utility's allowed return on rate base is established to compensate the utility's investors for the various business risks it incurs, among them the risk that regulatory lag will delay the recognition of cost increases of revenue fluctuations in utility rates between base rate cases. *Id.* at 27. He testified that utility investors are also compensated through the rate of return for bearing the risk that the utility's costs or sales revenues could fluctuate between rate cases relative to the levels embedded in the utility's rates. *Id.*

(d) SDI Case-in-Chief. Mr. Smith testified that the Company's proposed Major Storm Restoration Reserve would shift all risk of fluctuating costs from major storms that occur between rate cases away from investors and onto ratepayers without providing any commensurate benefit to ratepayers. Smith Direct, at 35. He also stated that I&M had provided no reliable safeguards against it deferring costs during periods in which it may otherwise have excessive earnings. *Id.* Mr. Smith testified that storm damage expense can be adequately addressed for ratemaking purposes without the need for piecemeal ratemaking and that I&M's proposal should be rejected. *Id.* at 35-36.

(e) I&M Rebuttal. In his rebuttal testimony, Mr. Krawec discussed the testimonies of Mssrs. Blakley, Selecky and Smith. Mr. Krawec theorized I&M's requested special accounting treatment for major storm damage expense would "alleviate the issue of the level of major storm damage" expense to include in base rates. Mr. Krawec said "use of a reserve allows I&M to recover the true costs of a major storm without the need to use other funds already allocated to other necessary O&M activities." Mr. Krawec said in some years, I&M may not incur the level of the major storm expense reflected in the proposed revenue requirement, but in some years I&M will spend more than the amount in the reserve. Mr. Krawec suggested that due to the nature of the reserve, which utilizes a true-up mechanism, the rates charged to I&M customers will ultimately reflect only the true costs of a major storm- no more and no less.

Mr. Krawec suggested OUCC witness Blakley's understanding of I&M's request for a Major Storm Damage Reserve is incorrect. Mr. Krawec said Mr. Blakley calls I&M's proposal a "hedge," "scheme," and "single issue ratemaking." Through cross-examination by the OUCC, Mr. Krawec acknowledged that Mr. Blakley's description of Petitioner's proposed special regulatory treatment was accurate. Mr. Krawec also acknowledged that the dictionary definition of "hedge" "a means of protection or defense, esp. against financial loss" and "scheme" "a systematic plan of action" accurately applied to the special regulatory treatment for which Petitioner seeks authority.

Mr. Krawec said I&M is a regulated cost-of-service utility and is entitled to recover reasonable and prudent expenses, including major storm expenses through the ratemaking process. Mr. Krawec suggested I&M's proposal is not unnecessary or contrary to traditional ratemaking. He said it recognizes that storm expense is a necessary cost of providing service. Mr. Krawec said because storm expense can be volatile, I&M's proposal provides a reasonable means to reflect in the price for electric service the true cost of major storms.

Mr. Krawec said traditionally basic rates are set with a normalized amount of major storm costs. Mr. Krawec said in the past I&M has incurred costs of major storms that exceed the amount recognized for ratemaking purposes. Mr. Krawec said that I&M can reasonably expect to incur such costs in the future.

Mr. Krawec said when large storms damage electric systems, a utility engages in a massive round-the-clock effort to restore power quickly. He said such efforts can be daunting and costly. In addition to deploying the utility's own crew, the utility will call for assistance from other parts of the country and will incur the additional cost of these external crews such as wages, equipment rental, transportation, lodging, meals, etc. In addition, Mr. Krawec said the utility will incur equipment costs, miles of new distribution or transmission lines, new poles, transformers, cross arms, fuses, etc. to replace what was damaged or destroyed by the storm.

Mr. Krawec said the commission has previously recognized that restoring service after major storm events "can only be met by extraordinary efforts that oftentimes come at an extraordinary expense." *Duke Energy Indiana,* Cause No. 43743 (IURC 7/14/10), at 11.

From a regulatory policy perspective, Mr. Krawec said the utility should not be penalized in the ratemaking process for incurring this cost. Mr. Krawec argued I&M's Major Storm Damage Reserve proposal avoids penalizing I&M for incurring this necessary cost of providing service. Moreover, Mr. Krawec said it avoids the potential for a catastrophic storm to erode the Company's earnings and impair the Company's financial ability, impacts that adversely affect customers because they lead to increasing capital costs and diminish resources for other needs.

(f) Commission Discussion and Findings. Mr. Krawec asserted that I&M has and can incur costs that far exceed the "normalized amount" of Major Storm Expense reflected in the revenue requirement. Mr. Krawec stated this is evident with the $14 million and $15 million level of storm damage in 2008 and 2005, respectively. Relying on the table provided by OUCC witness Mike Eckert, neither of these two major storm events occurred during the years covered by Petitioner rates as set by its most recent rate order in Cause No. 43306, which was issued in March of 2009. Indeed, the table prepared by Mr. Eckert based on information provided by Petitioner shows major storm expense in the years following the issuance of the final order in Cause No. 43306 of $996,430, $4,391,227 and 4,602,039. During

Cross-examination by the OUCC, Mr. Krawec acknowledged that I&M has embedded in rates an amount for major storm damage that is no less than $4,770,000. Thus, looking at the last three years for which we have evidence of major storm damage expense in the evidentiary record, I&M's major storm damage expense has not exceeded the amount embedded in rates in any year. In those three years I&M has had embedded in rates a total of no less than $14.3 million against actual major storm damage expense of less than $10 million. Thus, in those three years, I&M pro forma revenue requirement for major storm damage expense has exceeded actual major storm damage expense by more than $4 million.

The $14 million and $15 million level of storm damage in 2008 and 2005 referenced by Mr. Krawec would have occurred under the rates established by the final order in Cause No. 39314, which was issued in November of 1993. For the more than 15 years the rates established by that order were in effect, the record in this Cause does not permit any conclusion as to the total storm damage expense for all of those years. Nor did Mr. Krawec know the level of storm damage expense that was included in rates. We strongly doubt the amount of major storm damage expense embedded in rates as a pro forma revenue requirement in Cause No. 39314 was equal to the $14 million or $15 million referenced by Mr. Krawec for 2008 and 2005. But not knowing the level of major storm damage expense for each of those fifteen years, we also cannot conclude that I&M incurred over those years more major storm damage expense than was provided as a pro forma revenue requirement in Cause No. 39314.

Mr. Krawec noted the "massive round-the-clock effort to restore power quickly," which he described as daunting and costly. In addition to deploying the utility's own crew, Mr. Krawec noted I&M would call for assistance from other parts of the country incurring the additional cost of wages for the external crew, equipment rental, transportation, lodging, meals, etc. In addition, Mr. Krawec noted the utility will incur equipment costs, miles of new distribution or transmission lines, new poles, transformers, cross arms, fuses, etc. to replace what was damaged or destroyed by the storm. Mr. Krawec stated that when the final costs are tallied, the bill can be financially devastating. With respect to distribution or transmission lines, new poles, transformers and other such equipment, those items are included in rate base, giving I&M the opportunity to earn a return on and of those items. With respect to the other items, we note that those costs are not new to restoring major storm damage expense, and I&M has been provided a pro forma annual revenue requirement to address such costs. There is no evidence that I&M has not been able to recover such costs that it incurred over the life of its rates.

It is also not the case that the so called Major Storm Damage Reserve frees up funds for use to restore power. As Mr. Blakley noted, the major storm damage reserve is not a reserve of cash funds but a mechanism to reimburse the utility for funds it incurs in excess of the amount embedded in rates.

Mr. Krawec describes major storm damage expense as extraordinary, volatile, irregular and unpredictable. While I&M cannot predict when a major storm event will occur, how often a major storm event will occur, or how much it will cost I&M to restore power to its affected customers, I&M can determine how it will prepare for such events and how it will respond to such events. For instance, I&M can mitigate major storm expense by engaging in reasonable and prudent tree trimming. I&M's rate payers have no such ability. But I&M's proposal for special ratemaking treatment would make its ratepayers responsible for the risk of all major storm damage expense in excess of the normalized amount already embedded in rates.

Petitioner has asked for extraordinary relief in this Cause by seeking from ratepayers funds to reimburse the company for its cost reduction initiative, which is described in more detail elsewhere in this order. One of the consequences of the utility's cost reduction initiative is no doubt fewer employees to assist the company in restoring power following major storm events. The number of employees Petitioner may retain is precisely the type of management decision that should remain with the company. Traditionally, once rates are established, it is the company that should bear the consequence of retaining too few or two many employees. In more ways than one, Petitioner has tried in this rate case to shift consequences of its actions (or inaction) that has traditionally and appropriately borne by the utility away from itself and toward its ratepayers. With respect to major storm damage expense, Petitioner is seeking authority not just for normalized storm damage expense as a pro forma revenue requirement but also for authority to require its ratepayers to insure it for all operating costs it may incur to restore power following a major storm damage event. During cross examination by the OUCC, Mr. Krawec was asked why the utility does not procure insurance for major storm damage expense. Mr. Krawec responded that "obviously, trying to get somebody to insure the damage related to a devastating ice storm, say, would be prohibitive." Tr. FF-79, lines 8 – 10. If no insurer would agree to be responsible for the cost of restoring power to I&M's customers because such restoration would be cost prohibitive, it seems unfair to shift this prohibitive cost to I&M's customers. Ratepayers are not currently nor should they be required in the future to be in the business of insuring I&M from storm damage expenses.

It is also the case that Petitioner's proposal would create a perverse incentive to employ fewer employees available to help restore power since one of the things that establishes whether a loss of power constitutes a major event is the length of time power is out. Put another way, Petitioner's proposal would eliminate a natural incentive to restore power as quickly as possible. Under Petitioner's proposal, Petitioner would likewise lose the incentive created by its ability to retain for any purpose whatsoever the amount embedded in rates that Petitioner does not need to call upon for power restoration. Petitioner's proposal has the potential effect of making Petitioner's service less reliable.

We also need to address Mr. Krawec's claim that the proposed special regulatory treatment would help prevent earnings erosion. We respond by noting that Petitioner has provided no evidence that it has suffered any material earnings erosion as a result of its efforts to restore power to its customers after major storm events.

We find that Petitioner's proposed special regulatory asset plan does not represent an appropriate solution for unpredictable storm expense since it would make the ratepayers responsible for the risk of all major storm damage expense in excess of the amount approved in rates. It is Petitioner that must respond to a given event and take precautions against a given event. The ratepayers are not in a position to do either. Therefore, Petitioner should bear the consequences of the risk. As the owner and operator of its system, I&M should be appropriately incented to do both.

To the extent I&M can take steps to reduce the operating expense caused by major storm damage, it is not unreasonable that I&M be permitted to enjoy the financial benefits of costs avoided through its prudence and diligence. But under I&M's proposal, any operating expense caused by a major storm event would not be borne by I&M but would ultimately be borne by its ratepayers. Costs avoided by I&M's prudence or diligence would only benefit I&M's ratepayers. Preservation of the integrity and reliability of I&M's transmission and distribution system is important. We consider it imprudent to remove any of the existing and natural incentives that promote preservation of the system.

In light of the forgoing, we reject Petitioner's proposal for special ratemaking treatment that it has called its Major Storm Damage Reserve.

(6) Nuclear Decommissioning Expense.

(a) I&M Case-in-Chief. I&M Witness J. Steven Kiser, Director of Trusts and Investments for AEPSC, discussed the nuclear decommissioning trust fund (the "Trust") established to decommission the Donald C. Cook nuclear facility ("Cook Plant") at the end of its useful life, specifically addressing the annual contribution necessary to ensure adequate funds were available for the decommissioning. Kiser Direct, at 2-3. He explained that the current level for decommissioning funding of $8.1 million should continue to ensure the Trust has sufficient funding. *Id.*

Mr. Kiser stated that the Trust is funded to ensure adequate funds to pay for the safe dismantlement of the Cook Plant and related facilities at the end of the useful life of the plant and to comply with certain State and Nuclear Regulatory Commission ("NRC") requirements. By funding the projected decommissioning costs now, customers who are receiving the benefits of the Cook Plant are allocated the costs to dismantle the asset. The NRC has established guidelines to ensure the adequacy of funds for the safe dismantlement, decontamination and disposal of nuclear generating units at the end of their useful lives. *Id.* at 5-6. These guidelines apply to both the amounts of fund contributions and the methods for funding the ultimate decommissioning of the units. Mr. Kiser testified that the NRC regulations specify a minimum amount to be accumulated in the fund for the radiological portion of the decommissioning and require I&M to prepare a biennial certification of assurance demonstrating it has accumulated at least a minimum amount of decommissioning funds. *Id.* at 5. He noted that the NRC required segregation of the Trust assets from I&M and that administrative control of the Trust be outside of I&M's control. Mr. Kiser explained that the Trust assets are held in a trust fund by The Bank of New York Mellon ("BNY Mellon"). Mr. Kiser stated that the investment decisions for the trust fund are made by an independent investment manager, NISA Investment Advisors, L.L.C. Mr. Kiser discussed this institution's performance and experience in managing both equity and fixed income investments in nuclear decommissioning trusts. *Id.* at 7.

Mr. Kiser stated that the current balance in the Trust is below the NRC minimum but indicated that when factoring in assumptions about the investment return of the assets, as permitted by NRC regulations, the Trust balance satisfies these minimum requirements. Mr. Kiser emphasized that the NRC minimum requirements are a base level of funding necessary just to assure the safe dismantlement and disposal of the irradiated components of the plant and do not consider the cost of dismantling the plant buildings and non-radioactive portions of the plant. He stated that I&M believes that it has the obligation to restore the plant site to a Greenfield condition, *i.e.*, the plant site should be restored to a condition comparable to that prior to the construction of the plant. He added that the NRC requirements also do not include the storage cost for spent nuclear fuel and noted that those costs will be required until the Department Of Energy ("DOE") takes possession of spent fuel. *Id.* at 6-7.

Mr. Kiser discussed the methodology used to determine an appropriate funding level. *Id.* at 2, 8-28. He explained that I&M had engaged Knight Cost Engineering Services, LLC to conduct a study (the "Knight Study") which evaluated 10 decommissioning scenarios and estimated the total decommissioning costs for the plant to range from $877 million to $1.5 billion in 2009 dollars. *Id.* at 8. He said the scenario cost estimates depend on the decommissioning method used, the method of storing the spent nuclear fuel, the location at which the spent nuclear fuel would be stored, the presumed date at which the DOE would open the nation's spent fuel repository, the rate at which the spent fuel will be accepted at the repository, and the rate of inflation. He indicated that the decommissioning expenditures for Unit 1 are scheduled to begin in 2034 and the decommissioning expenditures for Unit 2 are scheduled to begin in 2037, which are the end of the NRC operating license lives. He added that complete decommissioning of the Cook Plant is expected to take many years and decommissioning costs could continue for up to 60 years after the plant is shut down. *Id.*

Mr. Kiser discussed how he used the costs from the decommissioning study to develop the proposed funding levels. *Id.* at 8-28. He stated that the costs, expressed in 2009 dollars, were used as a base from which future decommissioning expenditures were projected. *Id.* at 8-9. These expenditures were escalated from their 2009 base using the formula prescribed by the NRC for development of escalation rates for nuclear decommissioning costs. *Id.* at 9. He explained that the NRC formula breaks the decommissioning costs into three components: labor, energy, and radioactive waste burial. The weight of each component is based on the detailed estimates in the Knight Study. The weighted annual inflation of all components comprises the total cost escalation for decommissioning. He stated that the purpose of escalating decommissioning costs is to ensure that cost forecasts account for the rate in which decommissioning costs are expected to increase over the long time horizon between now and the completion of the decommissioning process. He explained that for this case, the decommissioning cost escalation for the Cook Plant from 2009 to the expected end of the plant's life was based on historical updates of inflation components from the Bureau of Labor Statistics and recent estimates of waste disposal costs. *Id.* at 9.

Mr. Kiser stated that the escalation rate is a combination of several components, and was calculated for each year in accordance with NRC requirements. He said separate forecasts were made for each of the formula's component pieces: the forecasted costs of labor, the rate of increase for energy costs, and the cost of radioactive waste disposal. Costs not included in those specific categories were escalated at the general rate of inflation. The components were then weighted according to the detailed estimates from the Knight Study. *Id.* at 9-10. The weighted rates were then summed to determine the annual escalation rate for the cost to decommission the Cook Plant. *Id.* at 10.

Mr. Kiser stated that the Trust must pay taxes on the investment income and any investment gains that are realized in the portfolio. *Id.* at 14. He said the taxes paid detract from the growth of the Trust, and reduce the amount of funds that will ultimately be available to pay for decommissioning expenses. He noted the current tax rate on the Trust is 20%. He discussed the steps that have been taken to minimize the impact of taxes on the investment portfolio. *Id.*

Mr. Kiser stated that in previous filings, I&M has assumed that the DOE would fulfill its contractual obligation to accept and store spent nuclear fuel rods. *Id.* at 16. However, since funding for the national spent fuel repository has been canceled, it has become more likely that the spent fuel will remain at the plant site indefinitely. He stated that in the Knight Study, one scenario included an open-ended cost for storing the spent fuel at the plant site. Scenario 10 in the study included costs of $4.4 million per year (in un-escalated 2009 dollars) for permanent storage of the spent nuclear fuel at the plant site. Mr. Kiser stated that for the projections performed for this case, the annual costs for the storage of the spent fuel were escalated out to year 2100. *Id.*

Mr. Kiser stated that although the risk of an investment loss is commonly associated with an investment portfolio, the greatest risk to the Trust is the possibility of a shortfall - not having sufficient assets to fully pay for the cost of decommissioning the plant. *Id.* at 16-17. He said the investment risk can be managed and minimized by building and continuously monitoring a diversified portfolio. He stated that the risk of a shortfall in the Trust is more difficult to manage and would be more difficult to recover from. A shortfall would mean that the Trust has failed to meet its basic objective of fully providing for the decommissioning of the Cook Plant. Since the decommissioning activities will continue for many years after the plant is removed from service, the existence of a shortfall and the extent of a shortfall may not be known for some time after the decommissioning process begins. *Id.* Since annual contributions to the Trust would have already ceased and since the investments would be positioned in a conservative asset allocation to accommodate payments for decommissioning expenses, the shortfall could not be eliminated with either extraordinary gains or normal annual contributions. *Id.*

Mr. Kiser discussed the Monte Carlo simulation process he used to determine the likelihood of having sufficient assets available at the end of the Cook Plant's useful life to pay for the decommissioning expenses. *Id.* at 21-25. He stated that recent advances in Monte Carlo simulation software allow the model and the trial runs it produced to be audited and verified independently. *Id.* at 24. Mr. Kiser also presented a hypothetical sensitivity matrix in an attempt to project the effects of a reduction in the annual funding amount recognized in the cost of service and discussed the most likely decommissioning scenario *Id.* at 25-27. Mr. Kiser concluded that the current rate of funding is likely to be sufficient based on the current accumulated balances in the fund and the currently projected decommissioning costs, given the uncertainties of future cost increases and investment returns. *Id.* at 27-28. He explained that while there remains a substantial risk of funding failure, at this time, he does not recommend any change in the amount of contributions to the decommissioning trust. *Id.* at 28.

(b) OUCC Case-in-Chief. OUCC Witness Duane P. Jasheway, Utility Analyst in the OUCC Electric Division, recommended that no further contributions to the Trust for the Cook Plant be included in rates in this proceeding. Jasheway Direct, at 10. He indicated that the funding contributions are no longer necessary based on the current balance of the Trust and will lead to a further build-up of funds that he contends will not be needed to decommission the two Cook Plant units. *Id.* Mr. Jasheway demonstrated that over the last six years, the Decommissioning Fund increased annually on average by 7.88%, or by over $77.5 million per year. *Id* at 6. Mr. Jasheway showed that of the ten decommissioning scenarios explored in the Knight Study, nine of the ten are overfunded as of March 31, 2012. Mr. Jasheway further explained based on the current balance, these nine decommissioning scenarios are from 100.69% to 162.98% funded. *Id* at 8. Decommissioning Scenario 10, which Petitioner prefers, is 108.42% funded and is overfunded in excess of $105 Million. Mr. Jasheway stated that the Decommissioning Fund will continue to earn interest until it is depleted. He further explained if the decommissioning process begins, as Petitioner projects, in the year 2034, the Decommissioning Funds would earn interest at least until the year 2042 and could continue earning interest until the year 2098. *Id* at 9. He stated that if cost projections or earnings change at any time before the scheduled decommissioning of the units such that the existing funds no longer appear sufficient to fund the costs of decommissioning, then the need to resume decommissioning funding could be reevaluated at that time. *Id.* at 10. Mr. Jasheway disagreed with Mr. Kiser's conclusion that it is better to have a larger surplus of decommissioning funds because any excess can be returned to ratepayers because he contends there is the potential for a significant balance of excess funds to be returned to future ratepayers who may not have received power from the Cook Units and may not have paid for any of the funding contributions that led to that excess. *Id.* at 11.

OUCC Witness Ronald L. Keen, Senior Analyst within the OUCC's Resource Planning and Communications Division, also addressed the funding of the Cook Plant decommissioning, noting that while Units 1 and 2 of the plant are currently scheduled to retire in 2034 and 2037, respectively, Mr. Kiser had previously testified that the Electric Power Research Institute ("EPRI") was researching additional life extensions. Mr. Keen stated that an additional extension beyond the current 2034/2037 license expiration dates to operate the Cook Plant would factor into proper evaluation of the Trust's funding. Keen Direct, at 6-7.

Mr. Keen discussed his review of the ten decommissioning scenarios analyzed in the Knight Study. The Study calculated cost estimates for each scenario in 2009 dollars. *Id.* at 12. Based on his review, Mr. Keen testified that except for scenario 3, all of the scenarios presented in the study were currently overfunded, including the most likely scenarios 8 and 10. *Id.* at 12-16. He also disagreed with Mr. Kiser's modification of the Knight Study cost estimates for scenarios 4 through 10 to reflect ongoing storage of spent nuclear fuel rods. Mr. Keen testified that the federal government is responsible for the permanent disposal of spent nuclear fuel rods, and while the government has already breached its contractual obligations, it has paid damages to I&M and others to compensate them for this breach. Mr. Keen testified that as of October 2011, there are over twenty settlements covering 56% of the nuclear power reactors under contract with the DOE for disposal of spent nuclear fuel. Mr. Keen testified that I&M is one of the settling parties, and in 2011 negotiated a settlement for spent nuclear fuel costs in the amount of $14,125,864 (for costs through May 31, 2010) with future reimbursements authorized through December 31, 2013. Mr. Keen also noted the agreement can be extended by mutual agreement of both parties. *Id.* at 16-18.

Although Mr. Keen acknowledged a theoretically possibility that I&M would be required to continue to maintain dry cask storage of spent nuclear fuel rods indefinitely, he indicated such a result was unlikely because it would require the federal government to permanently walk away from its obligations and that there would be no advances in technology regarding the disposal of spent nuclear fuel rods in the next 80+ years. *Id.* at 18. Mr. Keen described research being done to explore recycling spent nuclear fuel rods which would reduce the amount and toxicity of byproducts requiring permanent disposal. *Id.* at 18-19.

Mr. Keen explained that the OUCC believed I&M should seek 100% of the cost for the storage of the spent nuclear fuel from the federal government. He also recommended that I&M should demonstrate why the current overfunding of the decommissioning fund, combined with the interest the fund is earning on a monthly basis will not sufficiently cover the costs of the spent nuclear fuel storage out to 2100 should scenario 10 be selected. *Id.* at 19-20. Mr. Keen acknowledged that the OUCC was not opposed to the inclusion of greenfield costs to return the area back to native habitat. *Id.* at 22. Although Mr. Keen indicated it was possible the scenarios in the study might increase in cost, he explained that it was just as likely the continued development and use of advanced technologies, automation and robotics could cause decommissioning costs to decrease over the next 25 years. *Id.* at 23-24.

(c) SDI Case-in-Chief. SDI Witness Smith testified that the market value of the Trust attributable to the Indiana jurisdiction was 71.5% of the total Trust. Smith Direct, at 28. He stated that this was higher than the Indiana jurisdictional allocation of the Cook Plant, which he asserted was 64.65519%. *Id.* at 29. Mr. Smith observed that I&M's FERC Form 1 indicated that its total asset retirement obligation for decommissioning the Cook Plant was $979 million and $930 million, respectively while the Trust assets were $1.3 billion and $1.2 billion, respectively. *Id.* Mr. Smith concluded that I&M's nuclear decommissioning obligation has been adequately funded at this time, since the Trust's assets exceed the asset retirement obligation by $321 million. Mr. Smith further observed that the Trust balance exceeded the total cost estimates in the Knight Study for eight out of the ten scenarios, further suggesting the Trust may be adequately funded at this time. *Id.* at 30.

Mr. Smith stated that if the Trust assets are growing faster than the liability (due to the after-tax earnings rate exceeding the cost escalation rate) then the funding sufficiency would continue to grow, even without additional funds being contributed to the Trust. He noted that I&M's assumptions for the return on the equities and cash in the Trust are the same used for the AEP pension plan, which had an assumed annual return of 7.75% for 2011. *Id.* at 31.

Mr. Smith also discussed I&M's Monte Carlo analysis, which demonstrated that except for scenario 3, the probability is high that the Trust will be adequately funded if contributions of between $4 to $8.1 million. He recommended that the annual funding level be reduced from $8.1 million to $4 million per year. *Id.* at 32-33. His recommendation was based on (1) a suggested Trust surplus of approximately $321 million, (2) the Trust assets attributed to Indiana exceed the jurisdictional allocation of the Cook plant; and (3) the Monte Carlo simulations run by I&M show high probabilities of sufficient funding at $4 million per year under all scenarios except scenario 3. In his cross-answering testimony, Mr. Smith testified that while the OUCC's recommendation is apparently not based on the results of I&M's Monte Carlo simulation runs, there appears to be merit in reducing the annual amounts to zero because of the current sufficiently funded status of the trust fund.

(d) I&M Rebuttal. Mr. Kiser discussed the testimony offered by the OUCC and SDI on the funding level for the Trust. He stated that the retirement dates for Units 1 and 2 of the Cook Plant are 2034 and 2037, respectively. He explained that

I&M has not conducted any studies evaluating the ability to extend the Cook Plant's useful life by an additional 20 years. Mr. Kiser argued that EPRI research being undertaken on the feasibility of extending the lives of nuclear plants does not mitigate the need to fund the Trust because the NRC has not indicated that it would ever grant a license extension past 60 years to any nuclear plant.

Mr. Kiser responded to suggestions that the cost of storage for spent nuclear fuels should not be included in the estimate of decommissioning costs, noting that the storage of spent nuclear fuel will extend for many years. He disagreed that the DOE was likely to fulfill its legal obligation to pick up the spent fuel from the plant site and safely dispose of it. He disagreed that recycling of the fuel was likely, noting that the Blue Ribbon Commission on America's Nuclear Future referenced by Mr. Keen stated that geological disposal remains the most promising and technically accepted method currently available for safely isolating high-level radioactive waste from the environment for very long periods of time. *Id.* at 6-7.

Mr. Kiser also discussed Mr. Keen's testimony that decommissioning costs were just as likely to decrease as to increase in the future. Mr. Kiser suggested that the trend in costs has been up. He added that a significant portion of the decommissioning will be disposal of radioactive wastes, the costs of which has been increasing by 3% more than the rate of general inflation. Kiser Rebuttal, at 8.

Mr. Kiser disagreed that the Trust is already sufficiently funded and requires no further contributions. He theorized why it is not appropriate to compare the current Trust balance as of March 2012 to the Knight Study decommissioning costs. He said that the Knight Study's costs were calculated in 2009 dollars and would need to be inflated to compare them with 2012 dollars. He said that a better analysis would escalate the individual cost components for decommissioning. *Id.* at 5, 11.

Mr. Kiser disputed Mr. Jasheway's calculations that the anticipated return in the assets of the Trust would be sufficient to ensure adequate funding at the end of the Cook Plant's useful life. He said that Mr. Jasheway's average annual Trust appreciation of 7.88% included contributions from Indiana, Michigan and wholesale customers which amounted to 31% of the increase. *Id.* at 10. Mr. Kiser said that when looking only at the actual investment rate of return from the fund, the return was 5.19% over a six year period. He stated that this level is slightly below the average return of 5.26% assumed in the Monte Carlo simulation. Mr. Kiser also speculated that the asset allocation of the Trust will be shifted to less risky investments with lower returns as decommissioning approaches. This alleged change will be made to reduce the risk in the portfolio and to provide sufficient available cash to pay for decommissioning expenses as they are incurred. *Id.* at 11.

Mr. Kiser discussed Mr. Smith's recommendations that annual funding for the Trust from I&M's Indiana customers be reduced to $4 million. He suggested Mr. Smith's analysis inappropriately compared 2009 dollars to 2012 dollars. Mr. Kiser said that his Monte Carlo analysis indicated that there is a one in three chance of a funding failure at Mr. Smith's recommended $4 million funding level. Mr. Kiser speculated that such a level of risk does not correspond with a high degree of confidence for funding adequacy. *Id.* at 18.

Mr. Kiser argued that Mr. Smith's comparison of the Trust balance to the asset retirement obligation for the Cook Plant as reported in FERC Form 1 is an invalid comparison. He said that an asset retirement obligation ("ARO") recorded for accounting purposes is not the same as the true economic cost of decommissioning a plant. He stated that the ARO discount rate applied to the projected costs is calculated by a formula that includes I&M's debt rate and an adjustment determined by the current level of Trust funding. *Id.* at 15. If the funding level is low, the annual ARO expense would be higher. Mr. Kiser said that using the corporate debt expense level renders the ARO sensitive to changes in that debt expense. He concluded that the ARO is an accounting concept that is not a reflection of the true economic cost of the future decommissioning of the Cook Plant. *Id.* at 15-16.

Mr. Kiser disagreed that modification of the Trust funding was necessary to more accurately reflect the allocation of Cook Plant expenses to Indiana, Michigan and wholesale customers. He said that the Trust has been accumulating for more than 29 years and that for the majority of that time, the demand allocation factor for the Indiana jurisdiction was more than 70% of the total. He suggested that the current expense should be based on the current demand allocation factors, as reflected in his analysis. *Id.* at 14.

Finally, Mr. Kiser discussed Mr. Smith's assumptions that the Trust will grow at a rate that exceeds the decommissioning cost escalation rate. *Id.* at 16. He suggested that it is impossible to know for sure what the growth rate for the Trust will be or what the escalation rate for decommissioning costs will be by the time the facility is decommissioned. Mr. Kiser said that while the assumptions for equities and cash in the Trust were the same as those for the AEP pension plan, the overall return on the two funds are not comparable because the funds are very different. He said that the expected return on the pension fund should not be used as a benchmark for the expected return on the Trust. *Id.*

(e) Commission Discussion and Findings. The purpose of funding an external nuclear decommissioning trust is to ensure that adequate funds are available to pay for the safe dismantlement of the Cook Plant and related facilities at the end of the useful life of the plant and to comply with certain State and NRC requirements. The nuclear decommissioning expense is included in the revenue requirement to allocate cost of decommissioning the plant to the customers who are receiving the benefits of its generation during its useful life. The funds collected must be placed into a trust account which neither I&M nor AEP can access for any purpose other than decommissioning the Cook Plant. Thus, these expenses are not equivalent to other expense adjustments in a rate case because the funding level approved will be incurred and the funds will be segregated in a separate account that can be used only to decommission the Cook Plant. Once the decommissioning is complete, if any funds remain, they will be returned to customers.

The parties disagree over the annual funding level of new contributions to the Trust. I&M Witness Kiser recommended continuing the current rate of funding of $8,100,000 annually, arguing that his statistical analysis assured that this level of funding would result in a 76% probability that the Trust would have sufficient funding to decommission the Cook Plant. Petitioner's Exhibit JSK-2. SDI and the OUCC recommended lower levels of funding—SDI initially proposed reducing annual funding to $4 million and subsequently noted that there is merit in the OUCC proposal to eliminate funding completely.

The evidence indicates some disagreement among the parties as to how the current balance of the Trust and its earnings history compares to the decommissioning scenarios laid out in the 2009 Knight Study. To the extent I&M desires to have current funding levels continue in its rates, the obligation to justify them falls squarely to I&M. To the extent I&M fails to do so, this Commission must decline to approve continuing contributions into the Trust. Nor does I&M assuage our concerns about the overfunding issues raised by the OUCC and SDI by arguing that excess contributions will someday be returned to ratepayers. Nuclear decommissioning is a long-term prospect, and the evidence shows it may prove to be an intergenerational bargain which could stretch out as long as the close of this century. As OUCC Witness Jasheway fairly points out, there can be no assurance that those ratepayers who now contribute will be those who ultimately receive any applicable refunds. Thus, this Commission should seek to find a reasonable balance between assuring along the way that adequate funds are being accumulated, and not ending up with an overfunded Trust at the expense of current ratepayers.

OUCC Witnesses Keen and Jasheway argue that Petitioner has not adequately supported its case that further funding of the Trust should be authorized at this time. They reached that conclusion, in part, by analyzing the balance of the Trust as of March 31, 2012 and concluding that in nine of the ten scenarios in the Knight Study, the estimated decommissioning costs were less than the balance of the Trust. SDI Witness Smith reached similar conclusions on the basis of a similar comparison. I&M Witness Kiser attempts to counter such arguments by pointing out that estimated decommissioning costs were calculated in 2009 dollars, and that earnings in the fund were subject to taxes which would reduce the amounts therein.

The OUCC's recommendation is also premised on the assumption that the Trust's returns will produce sufficient additional growth over the remaining life of the Cook Plant to provide adequate funds to decommission the Cook Plant. We note that even without the possibility of additional extensions raised in Mr. Keen's testimony, the Cook Plant's units are currently licensed to be in operation for 22 and 25 years respectively and that Mr. Kiser projects that final decommissioning of the plant could take 60 years. Even if the 7.88% increases noted by Mr. Jasheway include contributions in addition to investment earnings, the investment rate of return conceded by Mr. Kiser of 5.19% can be expected to result in substantial earnings over the long run as applied to the already existing sum of $1.285 billion that Petitioner concedes as the fund's liquidation value. Tr. EE-85. OUCC Witness Keen further discussed the potential for reductions in the cost to store spent nuclear fuel rods resulting from technological developments or for the government assuming responsibility for storage. We are aware that such technological development has not yet occurred. But given the already healthy state of I&M's Trust, the potential for such improvements as outlined by Mr. Keen gives us some additional reassurance that the Trust is adequately funded at this time.

In sum, we find and conclude that I&M's proposal to continue funding of the Trust at $8.1 million each year should be rejected. The Commission's decision provides reasonable assurance that funding will be available to fully decommission the Cook Plant at the end of its useful life and appropriately allocates the cost of such decommissioning between present and future customers who benefit from the Cook Plant.

(7) Pre-April 7, 1983 Spent Nuclear Fuel Trust.

(a) I&M Case-in-Chief. The Nuclear Waste Policy Act of 1982, signed into law on January 7, 1983, established that the Federal Government had responsibility to provide for the permanent disposal of spent nuclear fuel and the costs of such disposal were the responsibility of the generators and owners of the spent nuclear fuel. Kiser Direct, at 28. He stated that the DOE promulgated rules under this Act that relate, in part, to the disposal of spent nuclear fuel from commercial nuclear reactors including Cook Plant. *Id.* In June 1983, I&M signed a contract with the DOE that provided, among other things, for payment of fees to the U.S. Treasury for such disposal. *Id.* Mr. Kiser explained that the contract consisted of fees derived by two cost mechanisms. One mechanism was a one-time fee for nuclear fuel spent to generate electricity at civilian nuclear power reactors prior to April 7, 1983 ("Pre-April 7, 1983"). *Id.* He stated that the second mechanism was a fee per kilowatt-hour of generation for spent nuclear fuel resulting from the generation and sale of electricity on or after April 7,1983 ("Post April 6, 1983"). *Id.* at 28-29. So, in addition to the liability for decommissioning the nuclear plant, I&M also has an obligation to the DOE to pay for the disposal of spent nuclear fuel used prior to April 7, 1983. *Id.* at 29. Mr. Kiser explained that the obligation is a fixed amount that increases with interest accumulated each year. *Id.* Amounts included in the fuel cost adjustment mechanism for the Post-April 6, 1983 spent nuclear fuel disposal costs are required to be deposited quarterly with the U.S. Treasury. *Id.* He stated that those deposits will continue at the present level unless the U.S. Congress changes this program. Those amounts do not directly affect decommissioning. *Id.*

Mr. Kiser explained that on a total Company basis, the initial liability for Pre-April 7, 1983 spent nuclear fuel disposal was $71,963,830. *Id.* at 29. He said the liability increases each quarter based on the most current yield for 3-month Treasury bills. *Id.* It has increased through the accumulation of interest to $265,001,448 as of March 31, 2011, and will continue to increase in the future. Mr. Kiser stated that based on an energy allocation factor of 63.48797%, the Indiana jurisdictional liability was $168,244,040. *Id.*

Mr. Kiser explained that BNY Mellon holds the spent nuclear fuel trust fund, which is considered to be a non-qualified fund. *Id.* at 29-30. As such, contributions to it are not tax deductible and investment income and capital gains are subject to the corporate income taxes. *Id.* Mr. Kiser stated that to help mitigate the tax burden on the trust fund's earnings, the fund is invested in tax-free pre-refunded municipal bonds. *Id.*

Mr. Kiser testified that as of the end of the test year, the Indiana jurisdictional portion of I&M's spent nuclear fuel trust fund had a market value of $218,047,382. *Id.* at 30. Mr. Kiser explained that the spent nuclear fuel trust is greater than the spent fuel liability allocated to the Indiana jurisdiction, so the trust may be considered fully funded for the Indiana jurisdiction. *Id.* at 30-31. Mr. Kiser stated that it is important to note that this liability will continue to increase through the accrual of additional interest until paid. *Id.* He added that the liability can move from fully funded to less than fully funded through changes in the market value of trust fund securities, differences between the liability accretion rate and the investment earnings rate and other factors. *Id.* He recommended that there is no current need to resume funding for the Pre-April 7, 1983 spent nuclear fuel disposal fund. *Id.* at 2, 31-32.

(b) Commission Discussion and Findings. No party opposed Mr. Kiser's recommendation regarding funding for the Pre-April 7, 1983 spent nuclear fuel disposal fund. Having reviewed the evidence on this issue, we find that the funding for the Pre-April 7, 1983 spent nuclear fuel disposal should remain suspended for the time being.

(c) Reporting. We direct I&M to continue to monitor the level of funding for nuclear decommissioning and for Pre-April 7, 1983 spent nuclear fuel disposal. I&M has previously reported to the Commission on these matters and we direct I&M to continue to do so every three years.

(8) Cook-Unit 1 Outage O&M Expense.

(a) OUCC Case-in-Chief. OUCC Witness Eckert identified expenses associated with the Cook Unit 1 outage in test year pro forma operating expense. The OUCC recommended these amounts be excluded from operating expenses. Eckert (Confidential) at 33-34.

(b) I&M Rebuttal. On rebuttal, Mr. Krawec reiterated his testimony during the February 2012 hearing in this Cause that it was I&M's intent to exclude these expenses from the cost of service on the basis that the costs were out of period and related to an extraordinary event. He identified Petitioner's Rebuttal Exhibit A-R5 (Confidential), O&M Adjustment R40 as reflecting the removal of these expenses as proposed by OUCC Witness Eckert.

(c) Commission Discussion and Findings. The parties agree that expenses related to the Cook Unit 1 outage should be removed from pro forma test year operating expense. Therefore we approve Petitioner's O&M Adjustment R40 as reflected on Petitioner's Exhibit A-R5 (Confidential).

(9) Outside Legal Expense.

(a) OUCC Case-in-Chief. The OUCC proposed adjustments to Petitioner's Outside Legal Expense on two bases presented by OUCC witnesses Margaret Stull and Wes Blakley. Mr. Blakley proposed removing certain legal and consulting expenses associated with I&M's purchase of the assets of Fort Wayne City Light and Power as a non-recurring expense. Mr. Blakley explained in his testimony that I&M purchased the assets of Ft. Wayne City Light and Power after the Commission authorized the transfer through its order on August 10, 2011 in Cause No. 43980. Mr. Blakley noted that in this rate case, I&M included in rate base the net book value of Ft. Wayne City Light and Power of $11,591,119. I&M also included, as a pro forma operating expense, a combination of various payments made by I&M to the city, including amounts for the betterments and the right to serve Ft. Wayne customers, as well as depreciation associated with the plant, amortization of deferred carrying charges and a deduction for removal costs related to salvage. He noted that I&M also removed embedded lease payments to the city of Ft. Wayne that were approved in I&M's last rate case. Blakley, at 14.

Mr. Blakley noted that in addition to these payments, I&M has included legal and consulting expenses related to the acquisition in test year expenses. More specifically, Mr. Blakley noted that I&M included $218,828 for City Light Lease legal and consulting (appraisal) costs of which $147,124 was allocated to Indiana. Mr. Blakley explained that the legal and consulting expenses of $218,828 are directly related to the purchase of Ft. Wayne City Light and

Power. Therefore, Mr. Blakley said this amount should be eliminated as non-recurring and excluded from Petitioner's pro forma revenue requirement. Blakley, at 13 - 14.

Ms. Stull proposed the removal of all other test year legal expenses. Total Company legal expenses during the test year were $2,367,861 (Total Company) recorded in four (4) accounts under the department "Legal Outside Counsel." Ms. Stull noted that as part of the OUCC's due diligence, it requested all legal invoices over $10,000. She explained that, although Petitioner provided documentation for these charges, it redacted all information on the invoice except for the name of the law firm, a brief description of the matter addressed, the name of the attorney or employee who performed the work, total charges by attorney or employee, and total charges due. No indication of the number of hours worked by a law firm on any particular matter or the hourly rate was included in the invoices provided. Ms. Stull explained that at a minimum, the supporting documentation should include the subject matter, as well as the date, the name of the attorney providing the service, the hourly rate for each attorney, and the hours worked by each attorney for each matter included in the invoice. Without that information, a reviewing agency cannot determine the reasonableness of the legal fees. Therefore, Ms. Stull proposed a decrease of $2,163,259 (Total Company) and $1,452,885 (Indiana Jurisdictional) to eliminate net unsupported test year legal fees. Stull, at 15 -16.

(b) I&M Rebuttal. With respect to the outside legal expense associated with the Fort Wayne City Light Lease, Mr. Krawec said the costs incurred for the purchase of the Ft. Wayne City Light and Power were part of settlement agreements with the OUCC and Fort Wayne which the Commission found to serve the public interest and approved. Mr. Krawec said I&M continues to incur legal expenses related to the implementation of the Fort Wayne City Light Lease. He suggested this type of cost is a normal expense. He argued while the nature of the legal issue/representation may change, the incurrence of the expense will not. Mr. Krawec suggested the Fort Wayne City Light Lease cost should be reflected in the ratemaking process via a three-year amortization, not wholly excluded. Mr. Krawec provided a table stating the amount of Legal Outside Counsel Expense for the test year, the twelve months immediately preceding the test year and the twelve months immediately following the test year. Mr. Krawec stated that the test year level of legal expense is the lowest of the three periods. Krawec Rebuttal, at 21. Mr. Krawec suggested the table shows that I&M's test year level is conservative, yet representative of the ongoing level of legal expenses I&M expects to incur. Mr. Krawec suggested his table shows the inclusion of legal and consulting fees associated with the Fort Wayne City Light Lease did not contribute to an excessive expense level or one that is unrepresentative of an ongoing level of expense. *Id.* at 20-21; Rebuttal Table 1.

Mr. Krawec opined that the determination of a reasonable attorney fee also includes such matters as the result achieved, the responsibility in dealing with a sizeable or complicated business transaction, and the difficulty of the issues. *Id.* at 22. He said each of the legal bills I&M received in the test year was reviewed by I&M personnel or the AEPSC Legal Department familiar with the services rendered. For regulatory matters, the legal bills are submitted electronically to Mr. Krawec as the Director of Regulatory Services. After his review and approval, the bill is forwarded to the AEPSC Legal Department in-house attorney for further review and final approval for payment. *Id.* at 23. Consequently, Mr. Krawec thinks there is no basis upon which to conclude that any of the legal bills in question were unreasonable, unusual or out of the ordinary. *Id.*

(c) Commission Discussion and Findings. In its proposed order on this issue, Petitioner cited various cases and final orders of this Commission to support its proposition that its test year legal expense should be approved as its *pro forma* revenue requirement. Petitioner seems to assert that the OUCC, and any other party that may oppose Petitioner's inclusion of the entirety of its outside legal expense in rates, has the burden to show that the utility's corporate officers abused their discretion or that there be evidence of inefficiency or improvidence, otherwise the test year outside legal expense is presumed to be reasonable and then included in rates as a pro forma revenue requirement. Without addressing precisely what sort of presumptions may exist with respect to outside legal expense in the test year, Petitioner's argument seems to miss the point raised by the OUCC. If we assume for purposes of this argument that the OUCC and intervenors have the burden to show an abuse of discretion of the utility's corporate officers or that there be evidence of inefficiency or improvidence, as Petitioner asserted in its proposed order, then it is only fair and just that Petitioner submit the basis of the revenue requirement to the scrutiny of the parties that may have this asserted obligation.

The OUCC's witness, Ms. Stull explained that, although Petitioner provided documentation for the test year outside legal expense, it redacted all information on the invoice except for the name of the law firm, a brief description of the matter addressed, the name of the attorney or employee who performed the work, total charges by attorney or employee, and total charges due. Absent, according to Ms. Stull, was any indication of the number of hours worked by a law firm on any particular matter or the hourly rate. Ms. Stull explained that, at a minimum, the supporting documentation should include the subject matter, as well as the date, the name of the attorney providing the service, the hourly rate for each attorney, and the hours worked by each attorney for each matter included in the invoice. We agree that without that information, a reviewing agency cannot determine the reasonableness of the legal fees. Although stating that it should not be considered the only factor to consider in assessing the reasonableness of attorneys fees, Mr. Krawec acknowledged in his rebuttal testimony that the hourly rate is a factor to consider. (Krawec rebuttal, p. 23) Without the number of hours worked on a particular project or the hourly rate itself, the OUCC was denied the opportunity to consider this factor.

In his rebuttal testimony, Mr. Krawec contended that if the OUCC contested I&M's objection to its data request, the OUCC should have raised the matter with I&M and, barring an informal resolution, the OUCC could have filed a motion to compel with the Commission. He asserted the OUCC did not take these steps. There appears to be some dispute as to whether and to what extent the OUCC endeavored to procure this information through an informal resolution. We decline to become embroiled in that controversy.

In its proposed order, Petitioner asked the Commission to admonish the OUCC for not filing a Motion to Compel by noting that the Commission's rules, specifically 170 IAC 1-1.1-16, preclude requests for extension of time based on inability to complete discovery unless the parties have resolved the matter themselves or brought the issue to the Commission's attention. More specifically, 170 IAC 1-1.1-16(b) provides in pertinent part that "No continuance of a scheduled hearing shall be granted for inability to complete discovery unless the parties have complied with the foregoing provisions." In its proposed order, the OUCC responded that it did not seek a request for an extension of time or a continuance. Nonetheless, it is unfortunate that the OUCC did not bring the discovery dispute to our attention before this time, because we agree with the OUCC that a determination of whether outside legal expense should be considered reasonable depends at least in part on the hourly rate. The information the OUCC sought would have allowed it to decide whether any further investigation was reasonable.

Petitioner asks us to find that it is unreasonable for a party to exclude an expense based on the party's inability to complete discovery. We decline to make such a sweeping statement. One question is whether a party must call upon us to police every discovery dispute in order to perfect the rights of the party seeking discovery to maintain an expense should be disallowed. Again, we decline to make such a ruling. The issue in this case is whether on the whole and looking at the evidence presented to us whether Petitioner has established by a preponderance of the evidence that its outside legal expense should be approved. We agree with the OUCC that at a minimum it should be afforded in the supporting documentation for outside legal expense the subject matter, as well as the date, the name of the attorney providing the service, the hourly rate for each attorney, and the hours worked by each attorney for each matter included in the invoice. In I&M's next rate case, we expect I&M to make such information available to the OUCC, or any other intervening party, to the extent it seeks to include any such test year expenses as a *pro forma* revenue requirement. In the absence of such basic information to the agency responsible for protecting the ratepayers from unreasonable charges, I&M should not be permitted to include such expenses in its rates.

That does not address what we should do in this case, which we now address. During the cross-examination of Ms. Stull, Petitioner offered and we admitted documents describing the level of outside legal services during the twelve months preceding and twelve months subsequent to the test year. The OUCC did not have an opportunity to scrutinize these documents before it filed its case. Nor do the documents provide any information on the billable rates, particularly for the test year, the period on which Petitioner relies for its asserted revenue requirement. The hourly rates for the test year remain absent from the record. That the test year outside legal expense is comparable to the outside legal expense in the twelve months both before and after the test year, does not adequately support the reasonableness of the test year legal expense since those amounts have not been adequately reviewed for reasonableness and appropriateness.

There does not seem to be any dispute that Petitioner has incurred and will incur outside legal expense that is appropriate to include in rates. Consequently, we are reluctant to deny the entirety of Petitioner's outside legal expense in this case. Although it is unreasonable for Petitioner to withhold information its own witnesses acknowledges is a factor to consider in determining whether outside legal expense should be considered reasonable, we decline to deny the entirety of Petitioner's requested outside legal expense because of the particular procedural facts of this case. In the future, we expect I&M to be more forthcoming with the information supporting its outside legal expense that it seeks to recover from the ratepayers.

We next address the inclusion of the legal and consulting expenses associated with I&M's purchase of the assets of Fort Wayne City Light and Power, which the OUCC considered to be a non-recurring expense.

OUCC witness Wes Blakley proposed removing the legal and consulting expenses associated with I&M's purchase of the assets of Fort Wayne City Light and Power as a non-recurring expense. More specifically, Mr. Blakley noted that I&M included $218,828 for City Light Lease legal and consulting (appraisal) costs of which $147,124 was allocated to Indiana. Mr. Blakley explained that the legal and consulting expenses of $218,828 are directly related to the purchase of Ft. Wayne City Light and Power. Therefore, Mr. Blakley said this amount should be eliminated as non-recurring and excluded from Petitioner's pro forma revenue requirement.

Mr. Krawec responded that this type of cost is a normal expense. He asserted that, while the nature of the legal issue/representation may change, the incurrence of the expense will not. Mr. Krawec provided a table stating the amount of Legal Outside Counsel Expense for the test year, the twelve months immediately preceding the test year and the twelve months immediately following the test year. Mr. Krawec noted that the test year level of legal expense is the lowest of the three periods. Krawec Rebuttal, at 21. Mr. Krawec asserted the table shows that I&M's test year level is conservative, yet representative of the ongoing level of legal expenses I&M expects to incur.

For the first time in its rebuttal case, through Mr. Krawec, Petitioner indicated its outside legal expense for the twelve months both before and after the test year show a comparable level of expense. Mr. Krawec offered these values to show that the test year level of legal expense is the lowest of the three periods, making I&M's test year level conservative, yet representative of the ongoing level of legal expenses I&M expects to incur. This argument fails to acknowledge that the values of the two other twelve month periods, provided for the first time during Petitioner's rebuttal case, were not reviewed to determine whether those values included any amounts for outside legal expense that should likewise be considered non-recurring or otherwise inappropriate to include in rates. Mr. Krawec asserts that these expenses, which related to the acquisition of a utility, should be considered normal. We note that there is no evidence that Petitioner engages in such transactions on an annual basis or expects to acquire any additional utilities in the period these rates are expected to be in effect. We also note that such costs associated with acquisitions are often capitalized, underscoring the unusual nature of such expenses. In its proposed order, Petitioner noted that Mr. Krawec testified that, at a minimum, the cost should be reflected in the ratemaking process via a three-year amortization, not wholly excluded. Mr. Krawec does not explain why a three year amortization of this expense would be appropriate and we decline to so order. We agree with the OUCC that the legal and consulting expenses associated with I&M's purchase of the assets of Fort Wayne City Light and Power are a non-recurring expense and $147,124 (allocated to Indiana) should be excluded from Petitioner's test year legal expense. We do not address in this order whether it would be appropriate for I&M to attempt to capitalize this expense since such action may require a determination whether such action would be permitted by the settlement agreements in Cause No. 43980.

(10) Rate Case Expense.

(a) I&M Case-in-Chief. Petitioner proposed to include in pro forma rate case expense, among other items, amounts for Communications Counsel of America (CCA) Training ($47,521) and the Nuclear Decommissioning Study ($55,280). Mr. Krawec adjusted the test year operation expense to reflect the amortization of retail rate case expense and nuclear decommissioning study expense over a period of three years. Krawec Direct, at 20.

(b) OUCC Case-in-Chief. Mr. Eckert testified that he did not agree with Petitioner's proposal to include the cost of the Nuclear Decommissioning

Study, the cost of CCA Training, or the estimated life of Petitioner's rates.

He testified that the inclusion of the cost of the Nuclear Decommissioning Study in pro forma proposed rate case expense was inappropriate because the costs of the study were incurred and paid prior to the beginning of the test year. Eckert Direct, at 31. He testified that the last payment made to Knight Cost Engineering Services was December 14, 2009, three and a half months prior to the beginning of the test year. *Id.* He also testified that I&M in discovery responses could not produce a Commission Order authorizing it to defer the cost of the Nuclear Decommissioning Study. *Id.* at 32.

Mr. Eckert testified that he excluded the cost of the training provided by CCA because the services and skills sets taught can be used for more than just this rate case. *Id.* In general, CCA provided training on the regulatory process and communication skills to subject matter experts preparing testimony in the Indiana base rate case. *Id.* He also testified that six of Petitioner's twenty-one witnesses are employed by I&M, and those fifteen witnesses who are AEPSC employees can use the services and skill sets for other AEP companies for whom they provide services. *Id.*

Finally, Mr. Eckert recommended Petitioner amortize its rate case expense over four years instead of three. *Id.*

(c) I&M Rebuttal. Mr. Krawec cited the Commission's March 23, 1983 Order in Cause No. 36760-S1 at 8-9, which stated:

> Therefore, we find that the adequacy of the annual provision [for nuclear decommissioning] should be reviewed as an element of cost-of-service in each subsequent rate case brought by Petitioner before this Commission. In the event that three years elapse between Petitioner's rate case filings, Petitioner shall then separately review and report to the Commission on the adequacy of the then existing annual provision.
>
> Krawec Rebuttal, at 17-18.

He suggested that I&M's filing in this case complies with the directive in that Order. He stated it is not reasonable or fair for I&M to be required to incur the expense of a nuclear decommission study every three years and not allow I&M to recover the cost of complying with this regulatory requirement. Mr. Krawec said that the OUCC relied upon the report to support its recommendation to remove nuclear decommissioning expense from I&M's rates. He said that the nuclear decommissioning study costs are costs I&M will continue to incur in the future, with the next report to be submitted to the Commission in late 2012. *Id.* at 18.

Mr. Krawec disagreed with Mr. Eckert's recommendations concerning CCA training. He said that the CCA was retained to educate the subject matter expenses on the Indiana ratemaking process and the specific issues in this case to assist those experts in communicating with the Commission and other parties to this proceeding. He stated this type of case specific regulatory training and communication is outside the scope of the subject matter witnesses' day to day duties and the cost of acquiring and maintaining these services other than through a service such as CCA would be much greater. *Id.* at 19.

Mr. Krawec disagreed with the OUCC's request to amortize the retail rate case expense over a period of four years, asserting that the three year period proposed by I&M is a reasonable approximation of the period of time that rates established in this Cause will be in effect. He said as it pertains to the nuclear decommissioning study, this study is performed every three years and therefore it is appropriate to include a three year amortization of that study in the cost-of-service. *Id.*

(d) Commission Discussion and Findings. With respect to these particular rate case expenses singled out by Mr. Eckert, we find that Petitioner has overreached in including these costs.

With respect to the nuclear decommissioning study, we find that the 1983 order in Cause No. 36760-S1 does not go so far as to authorize the deferral of such costs. The nature of a base rate case is that certain costs will be within the test year, and others will not. Petitioner should not be allowed to "cherry pick" those costs which happen to be outside the test year.

Turning to the CCA training, we agree with OUCC Witness Eckert that such generalized training has not been shown to apply sufficiently specifically to this rate case, as is particularly shown by the fact that many of I&M's witnesses are AEPSC employees who will use this training for other AEP affiliates as well as I&M.

Finally, while we appreciate the possibility that I&M might seek rates in a shorter time period, we agree that amortization over four years is a reasonable balance taking into account that the rates set in this case might be in effect for considerably longer than four years.

(11) Non-Allowed/Non-Recurring Expenses.

(a) OUCC Case-in-Chief.

(i) Non-Allowed Expenses Ms. Stull proposed the exclusion of certain non-allowed expenses. Ms. Stull advised there are certain expenses that are not allowed to be included in a Utility's revenue requirement for ratemaking purposes. These costs include, among other things, charitable contributions, community relations, marketing, and lobbying expenses. Ms. Stull added that costs incurred for institutional or image-building are also not allowed for ratemaking purposes. She advised that these "non-allowed" costs provide no material benefit to ratepayers and are not necessary for the provision of electric utility service. As such, these expenses should not be borne by the ratepayers. She cited Ind. Code § 8-1-2-6(c) in support of her adjustments, stating that the costs incurred for institutional or image-building, charitable contributions, community relations, marketing and lobbying expenses are not allowed for ratemaking purposes and that these costs provide no material benefit to ratepayers and are not necessary for the provision of electric utility service. Stull Direct, at 9.

Ms. Stull acknowledged Petitioner recorded a significant amount of its charitable contributions, community relations, and institutional or image building activities "below the line" and, therefore, excluded these expenses from its revenue requirement. Further, Petitioner proposed O&M Expense Adjustment No. 37 to eliminate $441,290 of "value advertising" from its revenue requirement. *Id.*

Ms. Stull recommended elimination of an additional $2,144,452 (Total Company) and $1,443,378 (Indiana Jurisdictional) for costs related to charitable contributions, community relations, lobbying, and other non-allowed activities as follows: Community Relations (Total Company $751,839/IN Jurisdictional $505,282); IN Governmental Relations (Total Company $339,240/IN Jurisdictional $228,017); MI Governmental Relations (Total Company $200,016/IN Jurisdictional $135,917; I&M Communications (Total Company $415,145/IN Jurisdiction $279,301; Miscellaneous Non-Allowed Expenses (Total Company $259,334/IN Jurisdictional $174,609). *Id.* at 10. Ms. Stull explained how she determined and calculated her adjustment, noting it is based on a detailed review of Petitioner's test year general ledger transactions. Her review revealed several I&M departments that fit the definition of "non-allowed" activities including Community Relations, Governmental Relations, I&M Communications, and I&M External Relations. Her review also yielded additional non-allowed costs recorded across various accounts and departments. *Id.*

Ms. Stull explained that she excluded from her adjustment transactions that were already properly addressed by Petitioner such as advertising expenses, Indiana Energy Association dues, and regulatory expenses. Her adjustment also excluded all "below the line" transactions since these transactions are not included in Petitioner's proposed revenue requirement. Finally, Ms. Stull explained that she did not exclude Chamber of Commerce dues since the Commission has allowed that expense in rates. *Id.* at 11.

Ms. Stull explained that she eliminated 100% of certain departments but only 50% of others. Ms. Stull advised that generally, she eliminated 100% of all identified non-allowed expenses including community relations (image building) and governmental relations (lobbying) activities. She noted that in response to an OUCC data request, Petitioner provided responsibilities and duties for several of its departments. She considered there to be two departments that performed both allowed and non-allowed activities, the Communications Department and the External Relations Department. The provided descriptions indicate that, while both of these departments are involved in branding and image building, they also provide necessary communication services for employees and ratepayers. Therefore, Ms. Stull proposed the costs of these departments be shared equally between ratepayers and shareholders. *Id.* at 11-12. Ms. Stull explained she included labor costs in her adjustment because, for ratemaking purposes, there is no difference between a consultant providing lobbying, marketing, or image building services and an I&M employee performing the same services. In both cases, the associated expenses should be removed for ratemaking purposes. *Id.* at 12.

Ms. Stull also proposed the exclusion of costs related to the AEP Service Company's Washington D.C. office in the amount of $97,357 (Total Company) and $65,456 (Indiana Jurisdictional). Ms. Stull noted that according to Petitioner's response to an SDI data request (Attachment MAS–13), certain administrative costs related to the AEP Service Company's Washington DC office are included in test year operating expenses. She advised that Petitioner recorded the majority of the allocated costs related to this Washington DC office below-the-line thereby excluding these costs from the revenue requirement. However, she stated these administrative costs, which Petitioner included in test year, would not have been incurred absent the existence of the Washington D.C. office and, therefore, these costs should also be excluded from the revenue requirement. *Id.*

(ii) Non-Recurring Expenses.

(A) Baffle Bolts. Ms. Stull also addressed a non-recurring expense in her testimony. Ms. Stull explained that certain test year costs incurred are one-time expenditures that are not reasonably expected to occur in the future. She stated that the rates being set in this Cause should reflect Petitioner's normal, on-going annual revenues and expenses. Therefore, if an expense will not reasonably recur in the future, it should be eliminated from operating expenses included in the revenue requirement. Stull Direct, at 13.

Ms. Stull determined test year expenses related to the replacement of "baffle bolts" - $11,597,530 (Total Company) and $7,498,405 (Indiana Jurisdictional) were non-recurring. According to Petitioner's response to a data request, baffle bolts are used to "...fasten baffle plates in place inside the reactor vessel." Petitioner further advised "These plates provide structural support for nuclear fuel and also channels (sic) the reactor coolant through the core for heat removal. The original design at Cook included 832 baffle bolts." Petitioner further stated that no baffle bolts have ever been replaced in Cook Unit One and that, prior to the test year, no baffle bolts have ever been replaced in Cook Unit Two. Petitioner also stated that baffle bolts are designed for a 40-year life and are not routinely replaced during the original life span of nuclear plants. *Id.* at 13. Based on this response, Ms. Stull recognized that replacing baffle bolts is an uncommon occurrence and determined there is no reason to believe that baffle bolts will be replaced at the Cook Plant facility in the future. *Id.* at 13-14. She noted Petitioner expensed, rather than capitalized, these costs because, according to Petitioner "the work associated with the baffle bolts was a repair activity." Ms. Stull quoted the following explanation from Petitioner. "Repairs to existing capital assets are treated as expense. In addition, baffle bolts are not retirement units, rather they are sub-components to the reactor vessel itself." *Id.* at 14.

Because Petitioner does not consider these to be capital costs and because these costs are not reasonably expected to recur in the future, Ms. Stull eliminated most of these expenditures from test year operating expenses. Ms. Stull proposed amortization of the cost of baffle bolt replacement over the remaining life of the Cook Plant Unit 2. She noted that Cook Plant Unit 2 is currently licensed through 2037 yielding a remaining life of twenty-five (25) years (2037 – 2012). She advised that amortizing total costs of baffle bolt replacement over twenty-five (25) years yields an annual cost of $463,901 (Total Company) and $299,936 (Indiana Jurisdictional). Removing total test year costs and adding back the annual amortization of those costs yields an adjustment of $11,133,629 (Total Company) and $7,198,469 (Indiana Jurisdictional). *Id.*

(B) Cook Plant Fire Suppression System. Another non-recurring expense was addressed by Mr. Eckert. Mr. Eckert recommended that the Commission eliminate $1,775,761 in total company NFPA 805 expenses ($1,148,122 Indiana Jurisdictional) from operation and maintenance expense because it is a one-time non-recurring expense. Eckert Direct, at 31. He testified that these expenses are for the replacement of fire suppression systems at the Cook Nuclear plant due to Federal regulation NFPA 805. *Id.* at 30. Mr. Eckert also testified that I&M stated in response to OUCC Data Request 37-5 and 37-6 that the project is a one-time project and that Petitioner did not provide the date the last such project was performed or the date the project will be performed in the future. *Id.* at 30.

(b) I&M Rebuttal.

(i) Non-Allowed Expenses. Mr. Krawec suggested that Ms. Stull's removal of expenses based on the title of the department that incurred the expense was not appropriate. He speculated that she performed an inadequate review by basing her determination on the title of the department, not the nature or type of expense incurred. Krawec Rebuttal, at 24-25. He said that departments are used by I&M for budgeting purposes and that the department code does not drive the accounting for the costs incurred within that department. *Id.* at 24. Mr. Krawec said that all departments charge the FERC account based on the type of work being done, that I&M follows the FERC USOA guidelines to determine when expenditures should be classified as capital or O&M and that charges are included in above-the-line FERC accounts or below-the-line FERC accounts (recoverable / not recoverable) based on the type of work being done. *Id.* at 24-25.

Mr. Krawec discussed Ms. Stull's removal of 100% of the costs recorded by Department 10892-Community Relations by stating that I&M's Community Relations department handles a variety of tasks such as employee communications, customer communications, energy education, special events, and public information for emergency preparedness and serves as the primary point of contact for City and County officials in regards to economic development, safety, outages, crisis management and other key issues as they arise. *Id.* at 25. He said that I&M Community Relations personnel provide communication on I&M policies, plans and programs; I&M's position on specific issues of concern to the Company or industry; and, news of specific issue developments and events as they occur and that it plays a significant role in I&M's economic development activities. *Id.* at 25-26. Mr. Krawec said that I&M's economic development activities further the Company's mission of supporting business and commerce and building strong communities and that I&M's Community Relations employees, in addition to their other job duties and responsibilities, coordinate and support traditional local economic development activities, including community preparedness, business recruitment, and business retention. *Id.* at 26. He suggested that these are not "non-allowed" activities as Ms. Stull contended. He argued customers benefit from I&M's Community Relations efforts because they are better prepared to use energy efficiently and safely by the information provided through the communication materials and that the materials help customers have a better understanding of actions the utility is taking on their behalf. *Id.*

Mr. Krawec said that I&M agreed that certain additional expenses should have been either recorded below-the-line or removed from the case as "image-building." He explained that I&M's audited the $751,839 (Total Company) amount which Ms. Stull recommended be removed. He said that the audit resulted in below-the-line or image building expenses of $13,787 (Total Company) or $9,269 (Indiana Jurisdiction) that should be removed from the revenue requirement. He argued that the remaining expenses recorded by I&M's Community Relations department were prudently incurred and are appropriate to include in I&M's revenue requirement. *Id.* at 26-27; Petitioner's Exhibit A-R5 (Dept. 10892, a component of O&M Adjustment R41).

Mr. Krawec said that Ms. Stull's recommendation to remove 50% of the costs recorded by Department 12085-Communications was not appropriate. He said that I&M's Communications department is responsible for internal employee communications. *Id.* at 27. He stated that the audit identified actual below-the-line or image building expenses in the amount of $13,915 (Total Company) or $9,355 (IN Jurisdiction) that should be removed from the revenue requirement. He identified the activities I&M Communications department externally responds to and the variety of media used to communicate safety, storm, and educational information to its customers. *Id.*

Mr. Krawec suggested Ms. Stull's removal of 100% of the costs recorded by I&M's managers of state government affairs to Department 10384-IN Governmental Relations was not appropriate. He said that Ms. Stull incorrectly equated the department titles of "Governmental Relations" with "lobbying." *Id.* at 28. He said that the I&M State Government Affairs personnel work on various non-lobbying activities including the day-to-day monitoring of not only state legislation matters, but also certain federal bodies, such as Congress and the FERC, which regularly take actions affecting utility companies, including I&M. *Id.* He said that these employees also work with government representatives to educate and inform them regarding utility and customer issues critical to utility operations and customer service and the employees monitor issues that may impact I&M's nuclear plant. *Id.*

Mr. Krawec said I&M recognizes that a portion of the State Government Affairs personnel time may be spent on lobbying activities and has reviewed the accounts to determine what additional amount, if any, should be recorded below-the-line. *Id.* He said I&M determined that the costs (Total Company) recorded by Department 10384-IN Governmental Relations are as follows:

| | |
|---|---|
| Labor and related employee expenses | $229,211 |
| Outside Services | 52,297 |
| Office Space | 51,718 |
| Other | 6,014 |

He said the Company has already removed the labor and related employee expenses associated with lobbying activities to eliminate those expenses for the test year levels. *Id.* at 29. He testified that I&M disagreed that 100% of the labor and related employee expenses for the State Governmental Affairs employee should be removed from the revenue requirement. He said that upon reviewing the OUCC's testimony, I&M undertook a review of the activities of the employee that can be reasonably expected going forward to determine a representative amount to be included in I&M's revenue requirement. Based on this review, Mr. Krawec determined that the test year amount should be adjusted to exclude 15% of the employee's expenses from the revenue requirement. *Id.*

Mr. Krawec also testified that the office space charges reflected in the test year are for rents associated with I&M's Indianapolis office. He said this office is used by numerous I&M employees, including I&M's President, Vice President of External Affairs, Director of Regulatory Services and State Government Affairs employee and is used as an off-site office for employees traveling to Indianapolis for various activities, including hearings, workshops and meetings with the IURC, OUCC and other stakeholders. *Id.* at 29-30. Mr. Krawec said I&M

disagreed that 100% of the expenses associated with the Indianapolis office should be removed, but agreed that a portion should be removed. *Id.* at 30. He testified that considering the portion of time that the Department 10384 State Government Affairs employee spends on lobbying activities (15%) and the considerable amount of time others use that office for non-lobbying activity, I&M agreed that 10% or $5,172 (Total Company) associated with the Indianapolis office should be removed from the cost-of-service reflected in the revenue requirement. *Id.*

I&M agreed to remove Department 10384 amounts as follows:

> $34,382 - 15% of the labor and related expenses of $229,211 (Total Company)
> $52,297 - 100% of outside services of $52,297 (Total Company)
> $ 5,172 - 10% of the office space costs of $51,718 (Total Company)
> $ 6,014 - 100% of the Other costs of $6,014 (Total Company)
>
> *Id.*

Mr. Krawec said this results in an adjustment of ($97,864) (Total Company) or ($65,797) (Indiana Jurisdiction) from the cost of service. *Id*; Petitioner's Exhibit A-R5 , Dept. 10384, a component of O&M Adjustment R41.

Mr. Krawec testified that after reviewing Ms. Stull's removal of 100% of the costs recorded by Department 12381-MI Governmental Relations, I&M reviewed the costs recorded by Department 12381 to determine the employee time associated with below-the-line activities (30%) and for other activities (70%). *Id.* He said based on that analysis, I&M proposed to remove 30% of the rent/lease amount of $52,118 (Total Company) resulting in an adjustment of $15,635 (Total Company) or $10,512 (Indiana Jurisdiction). *Id.* at 30-31; Petitioner's Exhibit A-R5, Dept. 12381, a component of O&M Adjustment R41.

Mr. Krawec argued that Ms. Stull's removal of 50% of the costs recorded by Department 12380-I&M External Relations was not appropriate. He said the test year expenses in Department 12380 are related to the work performed by I&M's Vice President of External Affairs, Marc Lewis, who spent time on numerous regulatory issues impacting I&M. Mr. Krawec explained that, as in previous years, during the test year, Mr. Lewis participated in numerous Commission investigations and inquiries and Mr. Krawec provided various examples of this ongoing work. *Id.* at 31.

With respect to Ms. Stull's proposal to remove 100% of the costs of "Other Miscellaneous Non-Allowed Expenses" Mr. Krawec agreed that $95,828 (Total Company) or $64,222 (Indiana Jurisdiction) should be removed as shown on Petitioner's Exhibit SMK-R3. *Id.* at 32; Petitioner's Exhibit A-R5, O&M Adjustment R-42. He argued that the remaining expenses are appropriate as these expenses include costs related to various items including employee activities, employee education and safety. *Id.* He said these activities result in a safer and more productive work force, encourage growth in leadership and creativity skills, emphasize to employees the value that the Company places on maintaining an experienced and stable work force and, thus, give recognition to those employees who have benefitted the Company and its customers by achieving safety goals, operational goals and reducing employee turnover. *Id.* He also said that reduced turnover results in a savings of costs for recruiting, hiring, training and education of new employees. *Id.*

Mr. Krawec testified that Petitioner's Exhibit SMK-R3 reflects expenses for an Informational Center Open House which were incurred to develop employee engagement and focus for safety issues for all I&M Cook nuclear plant employees, including new outage workers, and temporary outage workers assigned to I&M's Cook Nuclear Plant. Krawec Rebuttal, at 32. He said the costs Ms. Stull sought to exclude go beyond employee recognition and safety events. *Id.* He said the proposed exclusion reflects costs incurred for I&M's association with Midwest Ozone Group ("MOG") (see Petitioner's Exhibit SMK-R3, line item "Jackson Kelly"). *Id.* at 33. Mr. Krawec explained that MOG is an affiliation of companies, trade organizations, and associations which draw upon their collective resources to advance the objective of seeking solutions to the development of a legally and technically sound national ambient air quality program based upon the use of sound science. *Id.* at 32-33. Mr. Krawec suggested this expense is prudent and reflects I&M's commitment to maintaining I&M's low cost of service, thus benefiting customers. *Id.* at 33.

Mr. Brubaker argued that the test year costs of the AEPSC Washington DC office reflected in the Company's proposed revenue requirement ($65,456 Indiana Jurisdictional) do not include lobbying costs. Brubaker Rebuttal, at 8. He said that while certain AEPSC employees in the Washington, DC office perform both a lobbying function as a portion of their job duties as well as other non-lobbying activities for the benefit of the affiliate companies, including I&M, other AEPSC employees in the Washington, DC office perform only non-lobbying activities for the benefit of the affiliate companies, including I&M. *Id.* He explained how the costs of the Washington, DC office are recorded to the above-the-line or below-the line FERC accounts based upon the specific tasks performed each day. *Id.* at 10-11. He said the Federal/External Affairs team in the Washington DC office monitors and participates in rulemakings and other public policy discussions at various federal agencies, such as the FERC, the Securities and Exchange Commission (SEC), and the Environmental Protection Agency (EPA) as part of their responsibilities. *Id.* at 10. He said the employees of the Washington, DC office assist in developing the quarterly and annual reporting disclosures related to these legislative items required by the FERC and the SEC. *Id.* Mr. Brubaker suggested these types of legislative monitoring and reporting tasks are reasonable business expenses, that would be incurred regardless of any lobbying activity, and it is appropriate that the test year amount of $65,456 be recoverable in the revenue requirement used to establish basic rates

(ii) Non-Recurring Expenses.

(A) Baffle Bolts and Cook Plant Fire Suppression System (NFPA 805 Costs). Both Mr. Chodak and Mr. Krawec discussed why I&M did not agree with the OUCC's removal of test year O&M expense incurred for the baffle bolt repair at Cook Unit 2 and for the Fire Suppression System at the Cook Plant. These witnesses suggested the OUCC position fails to recognize that numerous specific expenses incurred during the test year are representative of a type of expense prior to and after the test year. Chodak Rebuttal, at 4, 17-21; Krawec Rebuttal, at 14-17. These witnesses said that while some specific expenses may not be specifically incurred again for several years, there will continue to be other stand alone O&M expenses incurred at the Cook Plant (and elsewhere) in subsequent years. *Id.*

Mr. Chodak said the baffle bolt replacement is a reasonable and necessary cost of providing service. Chodak Rebuttal, at 17-18. He explained the nature and type of O&M expenses that were prudently incurred at the Cook Plant during the test year to maintain safe operation of the nuclear plant and suggested the test year amount is representative of future operations. *Id.* Mr. Chodak also said while I&M may not be replacing the baffle bolts in its reactor vessel every year, there will be other emergent work that will occur going forward. Chodak Rebuttal, at 18-19. Mr. Chodak said that while the cost of the baffle bolts were incurred during the test year, the Company continued to incur additional expense following the test year to inspect baffle bolts.

Mr. Krawec disagreed with Ms. Stull's recommendation that the baffle bolts be removed from I&M's test year expenses and amortized over the life of Cook Unit 2. He said should the Commission find that the baffle bolt replacement at Cook Unit 2 is an extraordinary one-time expense which is non-recurring in nature, this should not preclude I&M from recovering the cost in a timely manner through the ratemaking process. Krawec Rebuttal, at 15-16. He testified that the baffle bolt replacement was not a capital addition and therefore should not be amortized over the life of Cook Unit 2. *Id.* He also recommended that should the baffle bolt expense be removed from the test period annual expense, the cost of the baffle bolt replacement should be recognized for ratemaking purposes via amortization over a three-year period, which he suggested is reasonable because it approximates the period of time that rates established in this Cause will be in effect. *Id.* at 16. Mr. Krawec also said should the Commission approve recovery of the baffle bolt replacement expense over 25 years, the unamortized balance should be recorded as a regulatory asset and included in I&M's rate base in this Cause and subsequent general rate filings. *Id.*

Mr. Chodak clarified that while the NPFA 805 project was a onetime compliance cost, the cost of this project spanned multiple years. Mr. Chodak suggested this regulatory compliance cost is representative of ongoing compliance costs. Chodak Rebuttal, at 19-21. Mr. Krawec disagreed with Mr. Eckert's adjustment that eliminates the expense associated with the replacement of the fire suppression system at the Cook Plant for ratemaking purposes. Mr. Krawec suggested Mr. Eckert did not recognize the driver behind the activity resulting in the expense, which as Mr. Chodak argued, was required by federal regulations, NFPA 805. *Id.* at 18; Chodak Rebuttal, at 19. Mr. Krawec said that while the fire suppression system replacement may be a one-time activity, the driver is emerging/changing/developing Federal regulations that will continue to cause I&M to incur O&M expenses. Krawec Rebuttal, at 17. Mr. Chodak and Mr. Krawec suggested the Company will continue to incur costs to comply with NFPA 805 on a going forward basis. *Id.* at 21; Chodak Rebuttal, at 16-17. They said as new regulations are passed, and as current ones are revised, the Cook Plant will incur expenses for work necessary to be in compliance and that the associated cost of compliance will likely increase. *Id.* Mr. Chodak and Mr. Krawec argued I&M properly included the test year level of expenses in its proposed revenue requirement because these costs are representative of normal operations. *Id.* These witnesses suggested I&M's test year O&M expenses are necessary to the provision of service and are representative of normal operations, and as such this type of expense is property recognized for ratemaking purposes.

Mr. Krawec argued that if the Commission finds that the test year cost of the fire suppression system is a non-recurring extraordinary expense, the cost should not be excluded for ratemaking purposes because he believes it is a reasonable and necessary cost incurred to provide utility service. Krawec Rebuttal, at 17. He said that, at a minimum, this cost should be recognized for ratemaking purposes by amortizing the cost of the Fire Suppression System over a period of three years. *Id.*

(c) Commission Discussion and Findings.

(i) Non-Allowed Expenses. We approve the following reductions to the test year identified by Ms. Stull:

| Expense Category | Amount of Expenses Reduction |
|---|---|
| Community Relations | $751,839 (Total Company)/$505,282 (Indiana Jurisdictional) |
| IN Governmental Relations | $339,240 (Total Company)/$228,017 (Indiana Jurisdiction) |
| MI Governmental Relations | $200,016 (Total Company)/$135,917 (Indiana Jurisdictional) |
| I&M Communications | $415,145 (Total Company)/$279,301 (Indiana Jurisdictional) |
| Miscellaneous Non-Allowed Expenses | $259,334 (Total Company)/$174,609 (Indiana Jurisdictional) |

We accept Ms. Stull's proposal to eliminate certain non-allowed expenses totaling $2,144,452 (Total Company) and $1,443,378 (IN Jurisdictional) from Petitioner's O&M expenses as follows: Community Relations (Total Company $751,839/IN Jurisdictional $505,282); IN Governmental Relations (Total Company $339,240/IN Jurisdictional $228,017); MI Governmental Relations (Total Company $200,016/IN Jurisdictional $135,917); I&M Communications (Total Company $415,145/IN Jurisdiction $279,301); Miscellaneous Non-Allowed Expenses (Total Company $259,334/IN Jurisdictional $174,609). We find that Ms. Stull conducted a detailed review of Petitioner's test year general ledger transactions and through this review identified several departments that fit the definition of non-allowed activities. Ms. Stull was also able to find additional non-allowed costs recorded across various accounts and departments. Based on this review and Ind. Code § 8-1-2-6(c) we find it appropriate to eliminate the non-allowed expenses identified by Ms. Stull as they do not provide a material benefit to ratepayers. In her review Ms. Stull found two departments, Communications Department and the External Relations Department, which would normally be eliminated as non-allowed expenses, but the two departments perform both allowed and non-allowed activities. Ms. Stull proposed to share the costs of these two departments equally between ratepayers and shareholders. We agree with Ms. Stull's recommendation to share the expenses of the Communications Department and the External Relations Department equally between ratepayers and shareholders as the departments appear to provide a partial material benefit to ratepayers.

Ms. Stull also proposed the exclusion of costs related to the AEP Service Company's Washington D.C. office in the amount of $97,357 (Total Company) and $65,456 (Indiana Jurisdictional). The OUCC asserted the administrative costs, which Petitioner included in test year, would not have been incurred absent the existence of the Washington D.C. office and, therefore, these costs should be excluded from the revenue requirement. In his rebuttal testimony, Mr. Brubaker maintained the charges the OUCC proposes to disallow are appropriately recoverable as utility expenses since they would be would be provided even if no lobbying activities were performed in that office. In considering these two opposing positions, we first note that Mr. Brubaker himself does not work in the Washington DC office nor does he supervise any of the lobbyists and other personnel so assigned. Tr., DD-42-45. Consequently, Mr. Brubaker is relying on the ability of others to have made the appropriate interpretation of the various rules with respect to recording expenses in the proper accounts for ratemaking purposes. The Washington DC Office of AEPSC consists of registered lobbyists, who book 90% of their time to lobbying activities (below-the-line) as well as one administrative assistant and a public policy researcher, both of whom book 100% of their time to FERC Account 920 (above -the-line). Mr. Brubaker acknowledged during cross-examination that, while the office's one administrative assistant booked all of her time as an above-the-line expense, she was available to assist the lobbyists who Petitioner acknowledges spend 90% of their time engaged in below-the-line lobbying activities. Yet Petitioner's proposed ratemaking treatment does not acknowledge this relationship since 100% of the administrative assistant's time is booked above-the-line to be recovered in the rates of AEP's various regulated entities.

During questions from the Bench and more specifically from Commissioner Bennett, Mr. Brubaker was unaware of the Federal and state reporting requirements of AEPSC's registered lobbyists. Tr., DD-58. It seems plausible that the "quarterly and annual reporting disclosures related to these legislative items required by the FERC and the SEC," as referenced in Mr. Brubaker's rebuttal testimony, which the "employees of the Washington, DC office assist in developing" would include the lobbying disclosures required by law. It would seem that AEPSC's Washington D.C. Office is primarily engaged in lobbying, which is well established to be a non-allowed expense for ratemaking purposes. It would only follow that the administrative assistant assigned to that office would assist in the efforts for which that office as a whole is primarily engaged.

We think it is a logical inference that, in an office that consists of professionals that spend 90% of their time engaged in lobbying activities, the administrative staff assigned to that office would be similarly engaged. We approve the OUCC's adjustment to exclude the costs related to the AEP Service Company's Washington D.C. office in the amount of $97,357 (Total Company) and $65,456 (Indiana Jurisdictional).

Based upon these findings we find that I&M is not authorized to include in operating expenses for ratemaking purposes, the test year expenses for Community Relations, IN Governmental Relations, MI Governmental Relations, I&M Communications and Other Miscellaneous expenses, including the cost of the AEPSC Washington DC office, as reflected in the OUCC's case-in-chief totaling the amount of $2,144,452 (Total Company) and $1,443,378 (IN Jurisdictional).

(ii) Non-Recurring Expenses.

(A) Baffle Bolts. Ms. Stull identified non-recurring expenses related to the replacement of baffle bolts totaling $11,597,530 (Total Company) and $7,498,405 (Indiana Jurisdictional). Petitioner stated that no baffle bolts have ever been replaced in Cook Unit One and that, prior to the test year, no baffle bolts have ever been replaced in Cook Unit Two. Petitioner also stated that baffle bolts are designed for a 40-year life and are not routinely replaced during the original life span of nuclear plants. Because Petitioner does not consider these to be capital costs and because these costs are not reasonably expected to recur in the future, we agree that the expensing of these costs should be eliminated from test year operating expenses. The elimination of these costs will more accurately reflect Petitioner's normal, on-going annual expenses.

We agree that the Utility should be able to recover these costs, but these costs are not properly expensed. A more appropriate approach would be to amortize the cost of baffle bolt replacement over the remaining life of the Cook Plant Unit 2 as Ms. Stull recommends. The Cook Plant Unit 2 is currently licensed through 2037 yielding a remaining life of twenty-five (25). The amortization of the cost over twenty-five years yields an annual expense of $463,901 (Total Company) and $299,936 (Indiana Jurisdictional). We find that Ms. Stull's adjustment to remove $11,133,629 (Total Company) and $7,198,469 (Indiana Jurisdictional) from test year operating expense should be approved.

(B) <u>Cook Plant Fire Suppression System.</u> We similarly find that Mr. Eckert's reasoning on the NFPA 805 expenses is very persuasive. The record demonstrates that these are one-time expenses, that this is a one-time project, and that it is not likely to be performed in the future. The elimination of these costs will more accurately reflect Petitioner's normal, on-going annual expenses. We find that Mr. Eckert's removal of the $1,775,761 in total company NFPA 805 expenses ($1,148,122 Indiana Jurisdictional) from operation and maintenance expense is approved.

(12) <u>Workforce and Cost Reduction Initiative.</u>

(a) <u>I&M Case-in-Chief.</u> Company Witnesses Chodak and Krawec said during the test year the Company implemented cost reduction initiatives to reduce its workforce. Chodak Direct, at 14-15; Krawec Direct, at 18. Nearly 2,500 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Chodak Direct, at 14-15; Krawec Direct, at 18. This cost reduction initiative reduced the Company's cost of providing service, including reductions in payroll and associated employee benefits costs. I&M Witness Brubaker presented various adjustments to the test year to pass these savings to the customers by normalizing the test year data to reflect the effect of a reduced workforce. Brubaker Direct, at 9, 13, 15, 16; Appendix A.

Mr. Krawec said as a result of the cost reduction initiative undertaken by AEP and I&M, AEP recorded a $293 million pretax expense on a total system basis related to these cost reduction initiatives with I&M's total company share of these costs incurred during the test year being $43.5 million. Krawec Direct, at 18-19. He stated that the Indiana jurisdictional retail share of this amount is approximately $30 million. *Id.* at 19. Mr. Krawec said the Company has adjusted the test year operating expense levels to remove the one-time expense of the cost reduction initiative. He added that the adjusted test year O&M reflects the ongoing savings of the cost reduction initiative including reduced payroll costs and benefit costs. *Id.* He stated this benefits customers by reducing the overall revenue requirement. *Id.* He said the Company proposes to defer as a regulatory asset the $30 million Indiana jurisdictional portion of the expense of the cost reduction initiative and amortize that amount over three years. *Id*; Brubaker Direct, at 15.

I&M Witnesses Krawec and Chodak argued the cost reductions and the cost incurred to achieve these long term savings are both appropriately reflected in the proposed revenue requirement. Krawec Direct, at 19. On cross examination, Mr. Chodak said customers will receive $7.4 million net savings per year in O&M costs as a result of the workforce reduction initiative and that such savings will increase after the end of the amortization period. [Tr. at A-109- A-111].

(b) <u>OUCC Case-in-Chief.</u> OUCC witness, Mr. Eckert recommended the Commission deny Petitioner's request to amortize AEPSC's and I&M's portion of costs associated with AEP's Cost Reduction Initiative. Mr. Eckert stated two reasons why these costs should not be recovered in rates from ratepayers. First, he noted these costs are non-recurring. Second, he noted the company will have already recovered its cost to implement the cost reduction initiative program. Eckert, at 28. Mr. Eckert explained that this recovery will have occurred through the employee-related expenses it will recognize between the time the cost reduction initiative was implemented and the time new rates are established for Petitioner. Eckert, at 25.

Mr. Eckert testified that I&M's was charged $12,087,093 in expenses associated with AEPSC's portion of the cost reduction initiative program and that I&M directly incurred $31,466,957 in expenses associated with I&M's portion of the cost reduction initiative program. Mr. Eckert testified that the annual amortized expense for AEPSC's portion of the Cost Reduction Initiative was $4,029,031 and I&M's portion of the Cost Reduction Initiative was $10,488,987. Eckert, at 26.

Mr. Eckert testified that AEPSC is reducing its annual I&M O&M billings by approximately $7.1 million per year and Indiana Michigan's annual payroll cost is reduced by approximately $25.1 million. Thus, Petitioner spent approximately $12 million during the test year to reduce its annual O&M billings from AEPSC and spent approximately $31.5 million during the test year to save $25.1 million per year in I&M employee related expenses. *Id.* at 26.

Mr. Eckert testified that AEP anticipated approved voluntary severances would be complete and employees would leave the payroll no later than May 31, 2010. He went on to state that if the employees left by May 31, 2010, I&M's AEPSC O&M billings and its company payroll would have been reduced effective June 1, 2010 and I&M would have saved approximately $7.1 million through reduced O&M billings from AEPSC and $25.1 million in reduced I&M payroll expense for the 12 month period ending May 2011. Additionally, Mr. Eckert testified I&M will realize another $7.1 million in savings due to reduced O&M billings from AEPSC and another $25.1 million in reduced I&M payroll-related expense for the 12 month period ending May 2012. Eckert, at 27.

Mr. Eckert concluded that as of May 31, 2012, Petitioner's accumulated annual AEPSC employee-related expense savings of $14.2 million for the two-year period June 2010 through May 2012 will have exceeded the entire cost ($12 million) of the cost reduction initiative program and Petitioner's accumulated annual I&M employee-related expense savings of $50.1 million for the two-year period June 2010 through May 2012 will have exceeded the entire cost ($31.5 million) of the cost reduction initiative program as of May 31, 2012. *Id.* at 24 – 28.

(c) IG Case-in-Chief. IG Witness Selecky also recommended the total cost of the workforce cost reduction initiative be eliminated from test year O&M expense. Mr. Selecky agreed with Petitioner's removal of the severance and relocation costs from test year but said it is inappropriate to include amortization of these costs in the development of the test year revenue requirement. Mr. Selecky explained that since I&M implemented its cost reduction initiative in 2010, it has realized significant savings resulting from the employee reductions. Mr. Selecky added that his review of Mr. Brubaker's testimony and related exhibits and workpapers indicate these savings were not considered. Mr. Selecky testified that, by the time rates are established in this case, I&M will have realized more in total expense savings from the cost reduction initiatives than it incurred in severance and relocation costs. Mr. Selecky explained that the severance and relocation costs paid by I&M and the AEP Service Company and allocated to I&M was $31.5 million and &12.1 million respectively. Assuming a January 1, 2013 order date in this Cause, I&M would have generated about $52.2 million of benefits as a result of the initiative. Mr. Selecky's recommended adjustment would reduce I&M's *pro forma* O&M expense by $14.518 million. Selecky, at 23.

(d) SDI Case-in-Chief. SDI Witness Smith opposed inclusion of the workforce cost reduction initiative costs in I&M's O&M expense, stating they were non-recurring. Smith, at 19. He further stated there is no need for a prospective amortization of those costs to determine a revenue requirement for I&M's Indiana jurisdictional operations for purposes of this case. He testified that any remaining costs have already been absorbed by related savings experienced by AEP through the approximate effective date of new permanent rates in this proceeding. *Id.* at 20. As a result, Mr. Smith proposed removal of $7.112 million for I&M direct severance cost amortization and $2.732 million of severance cost amortization for AEPSC severance costs allocated to I&M's Indiana jurisdictional operations. *Id.* at 24.

(e) I&M Rebuttal. I&M Witness Krawec offered rebuttal testimony in response to the proposed removal from the revenue requirement of the test year expenses associated with the cost reduction initiative. He said because an expense is non-recurring does not mean it is not recoverable in either the test period cost of service or as an amortized regulatory asset. Krawec Rebuttal, at 10. He said the severance program was part of an ongoing business practice of managing expenses to ensure both acceptable service and low rates for customers while ensuring I&M's future viability to attract the capital necessary to make prudent investments to serve its customers in the future. *Id.* at 11. He said the Company and its customers will benefit from these initiatives for years to come and I&M should not be punished for making prudent cost beneficial decisions. *Id.* He suggested the cost reduction initiatives have positioned I&M to operate more efficiently in this troubled economy, but it should not be assumed the initiatives provided the Company with a financial windfall such that the net costs related to their implementation were recovered. *Id.* at 12. He acknowledged that it is clear from I&M and the OUCC's pre-filed testimony in this case that there are already savings from the cost reduction initiative program that will be reflected in the rates in this proceeding. *Id.* at 13.

Mr. Krawec suggested the Company has not previously recognized through the ratemaking process the cost incurred to produce the cost savings benefits. Krawec Rebuttal, at 11-12. He said in its Final Order in the Company's last basic rate case, Cause No. 43306, the Commission authorized I&M to earn Indiana jurisdictional net electric operating income of $152,467,000. The order in Cause No. 43636 adjusted the authorized return to reflect I&M's

clean coal technology investment. Mr. Krawec said I&M has not cumulatively over-earned its return allowed since that final order. He said I&M's Indiana jurisdictional return for the 12 months ended May 31, 2011 as filed in Cause No. 38702-FAC67 was approximately $47 million below the return authorized in Cause No. 43306. Mr. Krawec said this period was the immediate 12 months following the implementation of the cost reduction initiative. Moreover, the sum of the differentials beginning with Cause No. 38702-FAC59 through I&M's most recent filing, 38702-FAC68, is ($249,284,000). Mr. Krawec concluded the Company has not recovered through excess earnings the test year costs incurred to achieve the cost savings reflected in the proposed revenue requirement.

(f) Commission Discussion and Findings. I&M's witnesses explained that nearly 2,500 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies, reducing the Company's cost of providing service through a reduced workforce. As a result of the cost reduction initiative undertaken by AEP and I&M, AEP recorded a $293 million pretax expense on a total system basis related to these cost reduction initiatives with I&M's total company share of these costs incurred during the test year being $43.5 million and the Indiana jurisdictional retail share of this amount is approximately $30 million. The question we address is whether Petitioner should be permitted to defer that operating expense, part of which was incurred in the test year, and recover that expense over three years as a pro forma revenue requirement in Petitioner's rates.

The OUCC noted this expense is a non-recurring expense and stated it should be denied on that basis. Moreover, the OUCC, as well as Intervenors IG and SDI, explained in their respective cases that the cost of the workforce reduction to I&M (Indiana jurisdictional) will have already recovered through the elimination of employee-related expenses it recognized between implementation of the initiative and the rates established by this order. In considering this issue, we recognize that ratepayers receive a benefit from this workforce reduction through lower *pro forma* operating expenses reflected in the rates approved by this order. But we also must consider that before this order, the only beneficiaries of this work force reduction was the Company itself and its shareholders because before this order, any savings achieved were not and could not be reflected in I&M's rates. Prior to the issuance of this order, Petitioner's ratepayers did not see any decrease in their rates as a result of the workforce reduction. On the other hand, while Petitioner chose to expend funds to implement the workforce reduction, the expenditure resulted in a freeing up of funds that more than offset expense of implementing the workforce reduction. But for the reduction in workforce, these funds would not have been available to the company for its discretionary use. Petitioner indicates we should ignore this factor, stating in its proposed order "there is no evidence that I&M's stockholders have received a return in excess of the authorized return because of the cost reduction program." We respond by noting that no party has suggested Petitioner's shareholders have "received a return in excess of the cost reduction program." We also respond that whether the cost reduction program resulted in earnings in excess of the authorized return is irrelevant to our inquiry. The fact is that prior to the issuance of this order, Petitioner's rates were based on a workforce that Petitioner has subsequently significantly reduced. The record does not permit us to conclude that Petitioner's pro forma revenue requirement in Cause No. 43306 (issued March 2009) setting that rate was overstated. Nor does the record permit us to conclude that Petitioner's workforce as it is today is insufficient to provide adequate service. We note that Petitioner began implementation of its workforce reduction in April of 2010, which was just over a year after we set Petitioner's rates in Cause No. 43306.

On April 14, 2010, AEP's then chairman, president and chief executive officer, Mike Morris provided an electronic message to its employees announcing an initiative to reduce corporate expenditures and decrease the size of the workforce. In the message, which was marked by the OUCC as its Cross-examination Exhibit 47, Mr. Morris announced that "revenues from retail and wholesale activities are not adequate to deliver continued value to shareholders, reward our hardworking employees and ensure adequate investment to deliver a reliable supply of affordable power to our customers." Thus, AEP acknowledged that the cost reduction initiative would provide a benefit or value to its shareholders. Mr. Morris also expressed his belief that the "creativity, innovation, and leadership in our organization will enable us to successfully find new ways to look at what work needs to be done and how the work gets done." This is precisely what an appropriately managed utility is expected to achieve.[9] It is reasonable that efficiencies achieved between rate cases would inure to the benefit of the utility and its shareholders until the next rate order, after which the ratepayers would enjoy the benefit of these efficiencies through rates lower than they otherwise would be.

A public utility has a natural incentive to exercise good management and good practices. A well managed public utility may be more profitable than a poorly managed one and its customers may be happier. A public utility is not guaranteed its authorized return but is merely afforded the opportunity to earn its return. A public utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. L.S. Ayers & Co. v. IPL 351 N. E. 2d 814, 821 (Ind. Ct of Appeals, 1976) citing Bluefield Waterworks & Improvement Co. vs. Public Service Commission (1923) 262 U.S. 679, 692-693. Petitioner responded to the fact that the savings achieved entirely offset the cost of the workforce reduction by stating in its proposed order that there was no evidence that I&M's shareholders have received a return in excess of the authorized return because of the cost reduction program. Whether Petitioner achieved its authorized return is irrelevant to this inquiry. A public utility is not afforded a guarantee to achieve its authorized return, as Petitioner's response suggests, but an opportunity. A public utility that earns a return in excess of the expectations used for ratemaking purposes is not required to issue refunds to its customers on that score. Likewise, a public utility is not permitted to use its failure to reach its authorized return as a basis to justify revenue requirements to which it would not otherwise be entitled. Petitioner's parent incurred an expense that had the net effect of eliminating a greater expense during the life of its previously established rates. The workforce expense eliminated was embedded in I&M's rates in Cause No. 43306. Before the issuance of the order in this Cause and the implementation of the rates it sets, I&M, and not its ratepayers, has been the beneficiary of the net savings created by its operating decision to significantly reduce and reconfigure its workforce. To the extent the reduction in workforce does not result in a material deterioration of service, as of the implementation of these new rates, I&M's ratepayers may now be considered the beneficiaries of the implementation of the workforce reduction that began nearly three years ago. Until this time, I&M's ratepayers

[9] One employee reacted to Mr. Morris's message by expressing wonder that the change had not come earlier. "Wondered how long it would be before we started cutting the work force. We have been fortunate that the company hasn't had to do this until now. Most companies started shedding work force long time ago." (Public's Cross-examination Exhibit 47)

were paying rates based on a workforce revenue requirement far in excess of the cost to I&M of the workforce now used to provide service. To require the customers to reimburse I&M for a cost fully offset and recovered by I&M through rates higher than they would otherwise be if the smaller workforce had been embedded in rates, would be inequitable.

We also should note that Petitioner is really seeking to recover an unusual operating expense it incurred in the past and which it does not expect to incur in the future. This raises the issue of whether Petitioner is asking us to engage in retro-active ratemaking. But having determined that I&M has already recovered the cost of implementing its cost reduction initiative and that it would be inequitable to seek to recovery of this cost from its ratepayers, we need not address whether it would be engaging in retroactive ratemaking to include in *pro forma* rates this past operating expense.

We reject Petitioner's request to include in rates any costs associated with the cost reduction initiative.

(13) Miscellaneous Tax Expenses.

(a) OUCC Case-in-Chief.

(i) Gross Revenue Conversion Factor. OUCC Witness Eckert proposed a Gross Revenue Conversion Factor of 166.5502% as opposed to 166.5520%, based on the current IURC Fee for 2011-2012. Eckert at 36. He used Petitioner's proposed state income tax rate and federal income tax rate in his calculation. *Id.*

(ii) IURC Fees. Mr. Eckert proposed a different IURC fee expense adjustment than Petitioner to reflect (1) the 2011-2012 IURC fee of .1178510% instead of the 2010-2011 fee; and (2) the OUCC's proposed revenue adjustments (as opposed to Petitioner's proposed adjustments). *Id.* at 37.

(iii) Utility Receipts Tax. Mr. Eckert also proposed a different Indiana Utility Receipts Tax adjustment to reflect the OUCC's proposed revenue adjustments. *Id.* at 36.

(iv) State and Federal Income Tax. Finally, Mr. Eckert proposed pro forma present rate Federal and State Income Tax adjustments reflecting the OUCC's proposed changes to various revenue and expense items. He proposed an adjustment to pro forma State Income Tax expense of $6,502,531 and an adjustment to pro forma Federal Income Tax expense of $34,407,692. *Id.*

(b) I&M Rebuttal. In its rebuttal exhibits I&M adjusted the IURC fee to reflected annualized March 2011 expenses; used the actual tax liability for the Utility Receipts tax based on the test period taxable receipts; updated the state and federal income tax calculations and reflected a gross conversion factor of 1.6655. Petitioner's Exhibit A-R5, at 12; Petitioner's Exhibit SMK-R1.

(c) Commission Discussion and Findings. Because we have rejected portions of Petitioner's proposed revenue and expense adjustments, we decline to accept its IURC fee expense, Utility Receipts Tax expense and State and Federal Income Tax expense. We find that the fees and tax calculations in the OUCC's filings are proper and that they have calculated Petitioner's fees and taxes in the appropriate manner.

**11. Net Operating Income at Present Rates.** Based upon the evidence and the determinations made above, we find Petitioner's adjusted Indiana Jurisdictional operating results under its present rates are as follows:

| | |
|---|---|
| Operating Revenues | $ 1,338,292,736 |
| O&M Expenses | $ 999,297,675 |
| Depreciation/Amortization | $ 102,658,072 |
| Other Taxes | $ 53,942,657 |
| State Income Tax | $ 7,456,546 |
| Federal Income Tax | $ 45,239,273 |
| Total Operating Expenses | $ 1,208,594,224 |

In summary, we find that with appropriate adjustments for ratemaking purposes, I&M's annual net operating income under its present rates for electric utility service would be $129,698,502, which represents a rate of return of 4.46% on its fair value rate base of $2,905,166,836. We find that this provides an insufficient opportunity for I&M to earn a reasonable return. Therefore, it is both reasonable and necessary for new rates and charges to be established.

**12. Authorized Revenue Requirement.** On the basis of the evidence presented in these proceedings, we find that Petitioner should be authorized to increase its basic rates and charges to produce additional operating revenue of $30,753,506. This revenue is reasonably estimated to afford Petitioner the opportunity to earn net operating income of $148,163,509 as follows:

| | |
|---|---|
| Operating Revenues | $ 1,338,292,736 |
| Less: O&M Expenses | $ 999,297,675 |
| Depreciation/Amortization | $ 102,658,072 |
| Other Taxes | $ 53,942,657 |
| State Income Tax | $ 7,456,546 |
| Federal Income Tax | $ 45,239,273 |
| Total Operating Expenses | $ 1,208,594,224 |
| Net Operating Income ("NOI") | $ 148,163,509 |
| Less: NOI at Present Rates | $ 129,698,502 |
| Increase Required | $ 18,465,007 |
| Times: Revenue Conversion Factor | 1.6655 |
| Jurisdictional Revenue Deficiency | $ 30,753,506 |
| Fair Value Increment | $ 0 |
| OATT Cost | $ 0 |
| **Authorized Increase in Revenue** | **$ 30,753,506** |

## 13. **Revenue Allocation.**

### A. **Cost of Service Methodologies.**

(1) I&M Case-in-Chief. Retail customers are served in the Indiana and Michigan jurisdictions and wholesale customers in both states comprise the wholesale or FERC jurisdiction. Because I&M provides service in three jurisdictions, it was necessary to determine the rate base, revenues, and expenses that relate to serving I&M's Indiana jurisdictional retail customers. The portions of I&M's rate base, revenues, and expenses attributable to serving Indiana jurisdictional retail customers were determined by the jurisdictional separation study using the process of cost allocation and direct assignment. The method used by I&M in calculating the demand and energy allocation factors was the average of 12 monthly loss-adjusted coincident peak demands ("12 CP"). *See* Direct Testimony and Exhibits of Witness Caudill.

I&M Witness Daniel E. High, AEPSC Regulatory Consultant - Regulatory Strategy Department, presented Petitioner's class cost-of-service study at present rates, Petitioner's Exhibit DEH-1, which allocates the total Indiana retail jurisdiction rate base, revenues and expenses to each rate schedule. He claimed that the cost allocation methodology used in that class cost-of-service study assigns costs among the customer classes in a fair and equitable manner based on principles of cost causation. He argued that customers who cause costs to be incurred are allocated such costs in the Company's class cost of service study. Mr. High also explained that the Indiana retail jurisdictional accounting cost information was assigned among the customer classes using the standard three-step process to assign costs: functionalization, classification, and finally, allocation. High Direct, at 5. He stated the five principal customer classes are residential, commercial, industrial, outdoor lighting and street lighting. *Id.* at 8. He explained that while some costs are directly assignable to a single class, or even a single customer, most costs are joint costs attributable to more than one type of customer and must be allocated to customers by an allocation methodology that is based on the manner in which the costs are caused by the different customers. He stated the joint costs are incurred based on the capacity demanded, the energy used or the number of customers. *Id.* He stated that when this process is completed and all of the costs are allocated to the customer classes, the result is a fully allocated cost of service study that establishes cost responsibility and the test year rate of return earned from each class, making it possible to determine the rates each class of customer should pay based on costs that are just and reasonable. *Id.* at 10. Mr. High classified production and transmission plant as 100 percent demand-related and allocated those costs to the customer classes on the basis of coincident peak demand. For the Indiana retail jurisdiction, Mr. High argued that the 6 CP was the most appropriate demand allocator considering the load profile during the test period ended March 31, 2011 reflects six monthly peaks, three during the summer and three during the winter, which supports the use of a 6 CP allocator. He claimed that the benefit of the 6 CP demand allocator is that each customer class is allocated its fair share of demand costs based on its contribution to the average of the six monthly seasonal peaks during the test period. *Id.* at 12-13.

As required by the terms of the Stipulation and Settlement Agreement approved in Cause No. 43306, Mr. High also presented a minimum system study (Petitioner's Exhibit DEH-2). High Direct, at 3. He testified that the minimum system approach does not accurately classify distribution poles, lines and transformers (accounts 364 through 368) considering such distribution facilities have a load carrying capability associated with them. He asserted that given the reality that demand drives the costs that are incurred for these facilities, and the fact that the Company plans and sizes its equipment to meet customers' peak demand on these distribution facilities, it is only appropriate to use a demand classification. *Id.* at 16. He described the Company's method of classification of distribution plant and stated it is a method that has been adopted in cases before this and other Commissions. He explained that the classification of services and meters as customer-related and primary and secondary poles, lines and transformers as demand-related recognizes the standard engineering practice to plan the distribution facilities to meet the maximum expected demand on the system, not necessarily the number of customers being served by the facilities. He stated it is more appropriate to classify services and meters as customer-related since a single service is required to serve each customer. For other distribution facilities, he explained, a diversified mix of commercial and residential customers will be served from those facilities, and it is the customers' demand placed on those facilities that drives the size and cost of the distribution facilities; not the absolute number of customers served from those facilities. Mr. High claimed that the benefit of the Company's approach in classifying distribution plant is that each customer class is being allocated its equitable share of distribution facilities based on contributions to peak demand associated with accounts 360-368, and number of customers related to accounts 369-373. *Id.* at 16-17.

Mr. High described in detail the allocation of production O&M expense, transmission O&M expense, distribution O&M expense, customer accounting, customer services and sales expense, A&G expense, depreciation and amortization expense, other regulatory expense items and taxes. *Id.* at 18-22. Mr. High also presented a summary of the resulting earned rates of return for each class shown in the class cost of service study. He explained that I&M Witness David M. Roush, AEPSC Director-Regulated Pricing and Analysis, utilized the earned rates of return for each class as a basis for the allocation of the revenue increase required for each class.

(2) OUCC Case-in-Chief. OUCC Witness Emma L. Nicholson, Economist at Exeter Associates, Inc. provided testimony based on her evaluation of I&M's proposed allocation of the jurisdictional cost of service among the customer classes. She stated that I&M has made significant investments in coal- and nuclear-fired baseload plants and that these investments were made, in part, to reduce the total cost of generating electricity. Dr. Nicholson explained that because investments in production plant are driven by both energy usage and peak demands, it was appropriate to allocate production plant on both load characteristics. Nicholson Direct, at 13. She proposed a Peak and Average (P&A) allocator that classified a portion of I&M's Indiana jurisdictional production plant as energy-related and the balance as demand-related. The energy-related portion was allocated to the classes based on test year energy usage and the demand-related portion was allocated on the four highest monthly coincident peak demands. She selected a 60-40 percent demand-energy split for the P&A allocator, which was roughly equal to I&M's Indiana jurisdictional load factor during the test year (59.4 percent). *Id.* at 14-17.

Dr. Nicholson also recommended that the costs of transmission, sub-transmission, and primary distribution plant should be allocated on the basis of 12 CP demands because 12 CP demands better reflect the costs of the transmission and primary distribution system, which operates year round rather than only in peak periods. *Id.* at 17. Dr. Nicholson also testified that the FERC CP Tests show that the use of a 12 CP methodology is more appropriate for I&M than the 6 CP methodology. She demonstrated that I&M's test year Indiana Jurisdictional loads passed the first FERC CP test, were within three percentage points of passing the second, and failed the third. Dr. Nicholson explained, however, that the FERC CP test results for I&M's Indiana Jurisdictional loads were not as meaningful because the jurisdiction is planned and operated within the greater I&M and AEP-East systems. *Id.* at 20. She performed the three FERC CP tests on both the I&M total system and AEP East zone test year loads and found that both systems passed all three tests. She asserted that the FERC CP test results corroborated her recommendation to allocate transmission, sub-transmission, and primary distribution plant on 12 CP demands rather than 6 CP demands. *Id.* at 21. Dr. Nicholson further stated that a cost of service study based on 12 CP demands for production as well as for transmission, sub-transmission, and primary distribution plant would be an acceptable alternative to the OUCC if the Commission does not accept the P&A method. *Id.* at 28. She noted that the 12 CP methodology provides a broader measure of peak demand and so better reflects I&M's need to meet demands in all the hours of the year, as opposed to the more narrow 6 CP methodology. In that regard, Dr. Nicholson provided the Commission with the results of a 12 CP cost of service study, which yields significantly different rates of return by class than does the Company's 6 CP study. *Id.* at 29.

Dr. Nicholson also recommended that I&M redesign its Off-System Sales Margin Sharing Rider ("OSS Rider") in order to properly align the allocation of costs and benefits of I&M's production plant. Nicholson Direct, at 33. The OSS margins, which she argues were made possible by the production plant, are returned to ratepayers through the OSS Rider. She explained that under the current OSS Rider, margins from energy-related sales are returned on the basis of class energy usage while margins from capacity-related sales are returned to ratepayers on the basis of peak demands. *Id.* at 31-32. This treatment results in the majority of the off-system sales margins being returned to classes on the basis of class energy usage. *Id.* at 32. Dr. Nicholson testified that the OSS Rider should be redesigned to ensure that the OSS margins are returned to the customer classes in the same manner that the cost of production plant itself is allocated to the customer classes within the cost of service study. She argued that this change to the OSS Rider would better align the allocation of the costs of production plant with the allocation of the benefits that the plant confers to ratepayers (OSS margins in this case). *Id.* at 33.

In Cross-Answering Testimony, Dr. Nicholson asserted that IG witness Mr. Phillips' proposed cost of service study based on I&M Indiana's five (5) PJM peak load contributions should be rejected because the 2010 PJM peak load contributions ("PLC") did not drive the costs of I&M's embedded production and transmission plant. Nicholson Cross-Answering, at 14-15. She noted that the majority of I&M's production and transmission plant, including I&M's D.C. Cook and Rockport plants, were constructed decades before the AEP-East system joined PJM. She also explained that the five hourly loads that form the basis of Mr. Phillips' PLC study were heavily concentrated in just two summer months (July and August 2010) and thus did not reflect I&M's year-round operating conditions. *Id.* at 14. Finally, Dr. Nicholson noted that the basis for Mr. Phillips' PLC study, which was I&M becoming a stand-alone member of PJM, has not occurred. She asserted that the implications of stand-alone PJM membership were not known and measurable during the test year and as such, the PJM PLCs do not form a reasonable basis for allocating I&M's embedded costs. *Id.* at 13-14.

Dr. Nicholson explained her support for I&M's decision to classify distribution plant accounts 364 through 368 as demand-related and allocate these costs to the customer classes on the basis of localized non-coincident peak demands. She explained her agreement with I&M that the minimum system cost of service study was unusable because the study does not correct for the load-carrying capability of the minimum system itself. *Id.* at 9. Dr. Nicholson testified that failing to correct for the load-carrying capability of the minimum system results in the over-allocation of distribution costs to classes with low average demands, such as the Residential classes, because a significant portion of their loads could be served by the minimum system. Dr. Nicholson showed that almost 90 percent of the costs of distribution accounts 364 and 368 are classified as customer-related under I&M's minimum system study. Additionally, 63 percent of account 365 and 69 percent of accounts 366 and 367 were classified as customer-related. *Id.* at 8-9. She asserted that with such high estimated customer-related components, using I&M's minimum system study would over-allocate a substantial amount of costs to classes with low average demands. She also explained that correcting for the load carrying capability of the minimum system is not always possible. *Id.* at 7-8. She explained that the actual distribution system is a complex network that depends on customer demands, customer density, and the geographic location of customers and transmission lines. She agreed with I&M's decision to reject the minimum system study because it did not account for all of these factors. *Id.* at 4. Dr. Nicholson also noted that Mr. Heid, who argued for use of the hypothetical minimum system in his Direct testimony, did not demonstrate or define a constant relationship between the number of customers and the quantity of poles, lines, conduit or line transformers (accounts 364-368) in I&M's Indiana Jurisdiction distribution system. *Id.* at 5.

(3) <u>IG Case-in-Chief.</u> IG Witness Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc., testified that I&M's total Indiana jurisdictional revenue requirement and I&M's electric rates should be based on the actual cost of providing electric service to the Indiana jurisdiction and to each customer class. Phillips Direct, at 3. He asserted that the 5 CP method using the five PJM PLC peaks is the most appropriate cost of service methodology because the AEP East pool members intend to terminate the pool in January 2014 and I&M will operate as a member of PJM. *Id.* at 4 and 13. However, if it is determined that no significant changes have occurred with respect to I&M's operations, Mr. Phillips agreed the 6 CP method proposed by I&M should be used, but with a customer component for the allocation of distribution system costs. *Id.* at 4 and 14-15. He argued that I&M's proposed 6 CP cost of service study understates the level of subsidies, and therefore the LP and Industrial Power ("IP") rates of return, because it fails to use a customer component (minimum system) to allocate certain distribution system facilities. *Id.* at 4 and 16. Mr. Phillips also asserted that any method of cost allocation that utilizes a form of average demand or energy to allocate production and transmission investment is at odds with the dominant system peaks on the I&M electric system and should be rejected. *Id.* at 4.

In Cross-Answering Testimony, Mr. Phillips argued that Dr. Nicholson's proposal would reverse previous findings of this Commission with respect to cost of service methodology. He claimed the P&A method proposed by Dr. Nicholson inappropriately over-allocates production plant costs to high load factor and off-peak classes, is counter to Commission direct findings on this issue, and should be rejected. Phillips Cross-Answering at 2. He also argued that Dr. Nicholson's proposed allocation of distribution facilities on a 12 CP allocator is at complete odds with sound ratemaking and should be rejected. *Id.* at 3. He also asserted the 12 CP method is not reflective of the I&M system, I&M planning or reserves and should also be rejected. *Id.* Finally, Mr. Phillips criticized the OUCC's willingness to compromise and accept a 12 CP allocation methodology as an alternative to the OUCC's P&A study. *Id. at 3*

(4) Fort Wayne Case-in-Chief. Fort Wayne Witness Kerry A. Heid recommended that the Commission approve I&M's proposed 6 CP methodology for allocating electric generation production plant in the cost of service study. Heid Direct, at 3. Mr. Heid stated that he agreed with the proposed classification of I&M's electric generation production plant as 100% demand-related and the allocation to the various rate classes based on the 6 CP methodology. He noted that the Commission approved the use of the 6 CP methodology in I&M's last fully litigated rate case in 1993 (Cause No. 39314). *Id.* at 5. He argued that there have been few changes in I&M's generating unit portfolio or in its system operating characteristics that would warrant a change in the Commission's historical treatment of production plant investment on the 6 CP basis. *Id.* at 6.

Mr. Heid also recommended that the Commission approve the alternate Minimum Distribution System methodology prepared by I&M for purposes of classifying a portion of certain distribution-related costs as customer-related. *Id.* at 6. He disagreed with Mr. High's and I&M's rejection of the use of the Minimum Distribution System methodology for purposes of classifying distribution poles, overhead and underground conductors and conduit and line transformers. *Id.* at 7. Mr. Heid asserted that I&M's investment in lines, poles and line transformers is a function of two factors: (1) the length of lines and the number of poles and line transformers, and (2) the size of the lines, poles and line transformers. He claimed that the length of lines and the number of poles and line transformers, in turn, is a function of the number of customers. Thus, Mr. Heid asserted, there is a close and direct relationship between the investment in primary and secondary lines, poles and line transformers with the number of customers served, thereby establishing a reasonable basis for a portion of the lines, poles and line transformers to be classified on a customer basis for cost allocation purposes. *Id.* at 7-8.

In Cross-Answering Testimony, Mr. Heid recommended the Commission reject Dr. Nicholson's use of the P&A methodology. Mr. Heid claimed that Dr. Nicholson used multiple approaches to quantify the percentage split between demand costs and energy costs in her P&A allocator. He asserted that Dr. Nicholson's argument in this case is a repeat of arguments the OUCC presented in a number of previous electric rate cases, which the Commission has previously rejected. Heid Cross-Answering, at 4. Mr. Heid also argued that Dr. Nicholson's P&A methodology was subject to technical flaws. Mr. Heid recommended the Commission approve I&M's proposed 6 CP methodology to allocate production plant. Heid Cross-Answering at 4. He also disagreed with the OUCC's recommended use of the 12 CP allocation methodology and claimed that Dr. Nicholson has not offered any basis for the use of the 12 CP allocation methodology. *Id.* at 20.

(5) Kroger Case-in-Chief. In his Cross-Answering Testimony, Neal Townsend, a Director for Energy Strategies, LLC, presented the Average and Excess Demand method for the Commission's consideration in response to Dr. Nicholson's proposal to adopt the P&A method. He testified that he does not recommend the Commission abandon the 6 CP method. However, if the Commission were to adjust its approved production cost allocation method in response to Dr. Nicholson's argument to recognize average demand requirements, Mr.

Townsend recommended the Average and Excess allocator. Townsend Cross-Answering at 6.

(6) I&M Rebuttal. I&M Witness Roush responded to the OUCC's and Intervenors' recommendations regarding the class cost-of-service study. He disagreed with Dr. Nicholson's recommendation to use an energy-weighted demand allocation methodology for production plant, claiming that her approach is not internally consistent in its treatment of the allocation of all costs, including fuel costs, is not consistent with Commission-approved methodologies for Indiana electric utilities and is not appropriate for I&M based upon the facts presented in this proceeding. He argued that the Company's allocation methodology for production plant is the same methodology used in its previously filed rate case proceedings, has been thoroughly reviewed and analyzed by many parties. Roush Rebuttal, at 3. He also disagreed with Dr. Nicholson's recommendation to use a 12 CP demand allocation methodology to allocate transmission plant because the Company's retail class load profiles during the test period do not reflect a flat load curve, but rather two distinct seasonal summer and winter peaks. Roush Rebuttal, at 5-6. Mr. Roush claimed that the FERC CP test is more applicable in determining the demand allocation on a jurisdictional or total company basis. *Id.* at 6. He asserted, however, that because the retail class load shapes are noticeably different when compared to the Company's jurisdictional load shape, the 12 CP is not the most appropriate class cost-of-service demand allocation factor for Indiana retail purposes. Mr. Roush also claimed that it would be inappropriate to allocate the primary voltage portion of distribution plant based on a 12 CP demand allocation methodology. *Id.* at 7. He also argued that because the Company used a 6 CP demand allocation factor in its previous cases and the load profile continues to reflect six monthly peaks, it is only appropriate to continue the 6 CP demand allocation. *Id.*

Mr. Roush disagreed with Mr. Phillips's recommendation to use PJM PLC values as the basis in allocating demand costs among customer classes. He asserted that it is more reasonable that I&M evaluate and consider how its customer classes are contributing to I&M's six monthly peaks (not PJM's peaks). He noted there is no assurance that I&M will peak at the same time that PJM will peak. *Id.* at 3-4. He explained that the five PJM PLC peaks for the test year were all in the months of July and August 2010. He stated that because I&M has two seasonal peaks, this approach does not represent I&M's needs for planning its facilities based on the three summer and three winter month peak demands. He added that under the Company's demand allocation approach, the 6 CP method does consider how I&M's customer classes are contributing to I&M's three summer and three winter peak months, thereby, giving equal weight to both of these two peak seasons for the Company.

Mr. Roush explained that the Company did not propose to change its classification of distribution plant in this proceeding. The Company continues to classify distribution plant accounts 360-368 as demand-related and accounts 369-373 as customer related. The Company's classification and allocation of distribution costs as demand-related and customer-related is both well established and widely recognized. Mr. Roush stated that the minimum system approach of classifying a portion of accounts 364- 368 as customer related, as Mr. Heid and Mr. Phillips are advocating, does not recognize the Company's standard engineering practice of planning and sizing distribution facilities to meet the peak demand of the customers served by those facilities. As such, the peak demand on Company facilities, not the number of customers served by the facilities, causes the Company to incur distribution facility costs. See also Witness High Direct, at pages 13 and 14. Mr. Roush explained that Mr. Heid's and Mr. Phillips' proposals do not fully recognize the fact that the facilities, even the minimum facilities, included in accounts 364-368 have a load carrying capability. He said it is the Company's "actual practice" to plan and construct the equipment included in these accounts to meet expected peak demand. Clearly, it is demand that is the cost driver. Mr. Roush disagreed with Mr. Heid's view of the NARUC Manual and explained that the Company's classification of distribution plant accounts 364-368 is consistent with the NARUC Manual and is based on principles of cost causation. He concluded that distribution plant costs included in accounts 364-368 are incurred based on peak demand. Therefore, the costs included in these accounts should be classified as demand-related and allocated using the Company's demand allocation factors. He testified that the classification and allocation of distribution plant used by the Company continues to be an appropriate method due to its foundation in cost-causation. Finally, Mr. Roush disagreed with Dr. Nicholson regarding the need to achieve consistency between the allocation of OSS margins, and the allocation of the production plant costs that enable OSS margins to be earned. Roush Rebuttal, at 17. He also disagreed with Witness Joseph Jancauskas, Inovateus Vice President of Engineering, contention that I&M should consider implementation of a feed-in-tariff. *Id.*

(7) Commission Discussion and Findings. We find that the results of I&M's Jurisdictional Separation study should be accepted and used to determine I&M's Indiana Jurisdictional revenue requirement. The study is well supported by the evidence presented by I&M witness Caudill, and its use of a 12 CP allocation appropriately recognizes I&M's year-round sustained provision of electric service in the Indiana, Michigan and wholesale (FERC) jurisdictions. Retail customers are served in the Indiana and Michigan jurisdictions and wholesale customers comprise the wholesale jurisdiction. Because I&M provides service in three jurisdictions, it was necessary to first apply cost causation principles to determine the rate base, revenues, and expenses that relate to serving I&M's Indiana jurisdictional retail customers. The portions of I&M's rate base, revenues, and expenses attributable to serving Indiana retail customers were determined by the jurisdictional separation study using the process of cost allocation and direct assignment. The method used by I&M in calculating the demand and energy allocation factors was the average of 12 monthly loss-adjusted coincident peak demands ("12 CP"). *See* Direct Testimony and Exhibits of Witness Caudill.

There was little controversy related to I&M's Jurisdictional Separations study, but significant controversy related to I&M's cost of service study, which allocates I&M's Indiana jurisdictional revenue requirement among the customer classes. We generally agree with the criteria identified by I&M Witness High for determining the appropriateness of an allocation methodology, principally that it assigns costs to cost causers. Unfortunately, there was little agreement among the parties regarding how to properly achieve the goal of assigning costs to cost causers. For example, several competing proposals were put forth to allocate I&M's production assets, including the D.C. Cook nuclear plant and the Rockport coal-fired plant. The competing proposals included 6 CP, Peak and Average (P&A), and the 5 CP based on PJM PLC. As an alternative to its preferred P&A approach, the OUCC also put forth a 12 CP study and indicated that the 12 CP method is an acceptable, compromise alternative to the OUCC.

As explained below, we believe that a 12 CP allocation will most equitably allocate production, transmission, sub-transmission, and primary distribution costs among the customer classes. We recognize that this finding represents a change from the last litigated I&M rate case in which this Commission addressed the proper allocation of production, transmission and distribution plant. However, this finding retains the use of a coincident peak allocation method, which this Commission has long relied on and is consistent with the FERC CP tests that were conducted by OUCC Witness Nicholson. We also find the Petitioner's class cost of service study equitably allocates the costs of distribution plant accounts 364-373 among the customer classes. I&M rejected the use of a "minimum system" study to allocate a portion of distribution accounts 364 through 368 as customer related. The evidence described below strongly supports I&M's judgment on this aspect of cost of service.

(a) Demand Allocation Methodology. I&M proposed to classify electric generation production plant as 100% demand-related and allocate it to the various rate classes based on the 6 CP monthly loads for the three summer months of June, July and August and the three winter months of December, January and February. This Commission approved the same demand classification and 6 CP allocation methodology for production plant in I&M's 1993 rate case, Cause No. 39314, nearly twenty years ago. More recently, we found in Northern Indiana Public Service Company ("NIPSCO") Cause No. 43526, that "Much of the capital investment costs at issue were, in fact, incurred to meet NIPSCO's energy requirements at lower costs thereby minimizing the total cost of service" Cause No. 43526 at 85. We went on to conclude that, "This is consistent with the evidence that NIPSCO's system was designed, planned and built in material part to serve the loads of its energy intensive industrial customers." *Id.* It was for these reasons that we ruled that a 12 CP methodology should be used rather than NIPSCO's proposed 4 CP methodology.

A similar situation and similar disagreements present themselves in this case, except that I&M's 6 CP method was approved in the last case in which a decision was rendered in Cause No. 39314 in 1993. In that Order, this Commission explained that "We are not convinced that the Company's 6 CP methodology is superior to the 12 CP methodology utilized in I&M's previous cost-of-service studies." Cause No. 39314 at 171. In that case, we were unable to find sufficient support in the record for a 12 CP methodology. However, we noted that "the 12 CP method is often utilized to reflect the full range of operating realities throughout the year including system demand, scheduled maintenance, and reserve requirements." *Id.* Unlike Cause No. 39314, the record in this case strongly supports a 12 CP methodology. Dr. Nicholson's testimony showed that the FERC CP tests support allocating transmission plant on 12 CP demands. This Commission also has a long and consistent preference for using the same measure of coincident peak to allocate the costs of production and transmission plant. Cause No. 43526 at 85. Furthermore, as was the case with NIPSCO, a large portion of I&M's production and transmission plant was also incurred to meet industrial energy demands at lower total costs throughout the year. As we stated in Cause 43526, we are not prepared to abandon our long-standing reliance on the use of coincident peak allocators for these costs, and so we do not accept the use of Dr. Nicholson's P&A methodology. However, we do agree with Dr. Nicholson that a broader CP method is called for. That concern, coupled with the FERC CP test results, convinces us that a 12 CP cost of service study will better suit the interests of an equitable allocation of the costs of service among the various customer classes in this proceeding. We therefore direct I&M to recalculate the class cost responsibilities based on the total allowed jurisdictional cost of service found appropriate in this Order using the 12 CP methodology to allocate production, transmission, sub-transmission, and primary distribution plant.

IG Witness Phillips advocated moving to a 5 CP based on the PJM PLC as a result of I&M's intention to terminate the AEP Power Pool effective January 1, 2014 and operate as a stand-alone member of PJM. Mr. Phillips also relied on I&M's report that its peak demand has been in the summer and that this summer peak is higher than its winter peak. However, no evidence was presented establishing that I&M's operating characteristics are properly reflected by the PJM PLC. Mr. Phillips relies on I&M's intent to terminate the AEP Power Pool at a date in the future and operate as a stand-alone member of PJM, but the impact of these changes on I&M's operations are presently unknown. As I&M Witness Roush noted, there is no correlation between the electric usage peaks I&M experiences and PJM's peaks, which raises questions about whether the PJM PLC is the appropriate mechanism for allocating I&M's production plant. We find that the PJM PLC method should be rejected because I&M did not construct its embedded production and transmission plant to satisfy the 2010 PJM PLCs. We are also persuaded by Dr. Nicholson's argument that the 5 PLCs are inappropriate for allocating production and transmission plant because they represent too narrow a measure of I&M's Indiana jurisdictional loads. In fact, the 5 CPs in Mr. Phillips' study all occurred in July and August. Clearly, I&M did not build its large base load power plants (e.g. Cook and Rockport) solely for the purpose of meeting July and August peaks. These base load assets, by definition and design, provide sustained low cost electric service throughout the year. For these reasons, we reject the use of Mr. Phillips' 5 CP method. The 12 CP method better and more equitably reflects the design of I&M's system to provide service throughout the year, and not just at times of seasonal peaks.

(b) <u>Transmission and Distribution Plant Allocation Methodology.</u> The parties also disagreed over the methodology of allocating transmission and distribution plant. The OUCC recommended that transmission, sub-transmission, and primary distribution plant be allocated based on a 12 CP methodology. Fort Wayne and the IG recommend reclassifying a significant portion of distribution accounts 364 through 368 as customer-related. This would result in allocating the majority of the costs in distribution plant accounts 364 through 368 on the basis of customer counts. The OUCC and I&M both strongly objected to this proposal as unduly burdensome to small customers and inconsistent with cost causation. As we noted above, we find the OUCC's recommendation to allocate transmission based on a 12 CP methodology should be accepted. Given that the Petitioner allocated its transmission, sub-transmission, and primary distribution plant with the same coincident peak measure (6 CP) within its cost of service study, we find that sub-transmission and primary distribution plant should also be allocated on 12 CP demands, adjusted for losses as appropriate. Both the I&M system and AEP East system FERC CP test results suggest that 12 CP demands, rather than 6 CP demands, should be used to allocate the costs of I&M's Indiana Jurisdictional transmission plant. We find that the I&M system and AEP East pool FERC CP test results are more important than the I&M Indiana Jurisdictional test results because I&M's Indiana jurisdictional operation is planned as part of I&M's total company system and the AEP East Zone.

We reject Fort Wayne's and the IG's recommendation to change the classification of distribution plant accounts 364 through 368 to classify and allocate a portion of these accounts as customer-related. The Company's classification of distribution plant accounts 364-368 is consistent with the NARUC Manual and is based on principles of cost causation. While there may be some theoretical logic to the concept of defining a customer-related component of distribution investment based on a hypothetical minimum distribution system that would connect all customers without supporting any appreciable amount of usage, the record reflects this is clearly a circumstance where theory and practice do not meet. I&M explained that its standard engineering practice is to plan its distribution facilities to meet the maximum expected demand on each component of the system. Accordingly, there is no reason to believe that the allocation of distribution costs would be made more accurate if a portion of the costs, determined based on a wholly theoretical construct, were allocated based on the number of customers being served by the facilities, particularly given that I&M's minimum system study classifies the majority of costs in distribution plant accounts 364-368 as customer-related. Given I&M's practice and the fact that it is practice, not theory, which causes the costs which I&M incurs, it is appropriate to classify and allocate I&M's distribution costs based on demand as proposed by the Company. Furthermore, I&M Witness High and OUCC Witness Nicholson explained that the minimum system approach was unsuitable for ratemaking purposes because it does not account for the load-carrying capability of the minimum system itself. Failing to account for the load-carrying capability of the minimum system over-allocates distribution costs to classes with small average demands and large customer counts, such as the Residential classes. Accordingly, we are persuaded by I&M's and the OUCC's arguments that distribution plant costs included in accounts 364-368 are incurred based on peak demand and should be classified as demand-related and allocated using the Company's demand allocation factors. I&M's proposed classification and allocation of distribution plant continues to be an appropriate method due to its foundation in cost-causation.

(c) OSS Margin Allocation. Elsewhere in this Order we addressed the problems with I&M's proposal to embed no amount of OSS margins in its revenue requirements study. Here, our focus is on the allocation of OSS margins among the classes. Fuel and variable production costs are subtracted from OSS revenue to calculate OSS margins. The amount of OSS margins in a given period represents a source of funds available to help cover the capital costs of I&M's production plants, which are the physical assets that enable OSS margins to be earned. The issue is how to fairly allocate the OSS margins to customer classes. We find that it is the existence of I&M's production plant that permits those OSS margins to be earned in the first place. To properly match costs with benefits, the margins from off-system sales should be allocated among the classes in the same manner that the production plant costs were allocated among the classes. Any other allocation of those margins would represent a mismatch between the allocation of the costs and benefits of I&M's production plant. Therefore, we conclude that it is appropriate to allocate the benefits of OSS margins, brought forth by that production plant, in a manner consistent with the allocation of production plant costs. An energy based allocation of all or a portion of OSS margins is at odds with the fact that the fuel cost to produce the energy is deducted to calculate OSS margins, which are available to help cover I&M's capital costs. Accordingly, we direct I&M to allocate OSS margins to the customer classes in the same manner that production plant is allocated to the customer classes within the cost of service study. This finding applies to OSS margins for base ratemaking purposes and for the future operation of the OSS margins sharing rider.

### B. Subsidy Reduction.

(1) I&M Case-in-Chief. I&M Witness Roush sponsored I&M's Indiana-jurisdictional cost-of-service study at proposed rates, including the calculation of the

interclass subsidies and the distribution of revenues to rate classes. He calculated the current subsidy for each class and explained the equal percentage subsidy reduction method of revenue allocation reflected in the Company's revenue allocation. Roush Direct, at 11-12. Mr. Roush explained that the process reflects the exercise of the principle of gradualism. *Id.* at 12. He explained that while it is not reasonable to eliminate all subsidies in this case, it is important to make progress toward eliminating interclass subsidies. *Id.* He added that the amount of such progress should be tempered by a recognition of the rate impacts on the various tariff classes. As such, I&M proposes to eliminate 50% of the current subsidies from all classes. *Id.*

(2) OUCC Case-in-Chief. OUCC witness Nicholson disagreed with Mr. High's cost of service results and therefore his calculation of inter-class subsidies. Assuming correct calculation of inter-class subsidies, Dr. Nicholson testified that she supports Mr. Roush's general proposal to move towards the full cost of service rates, but recommended that this be done in moderation, particularly given current economic conditions. She concluded that Mr. Roush's subsidy reduction methodology was a reasonable first step to establish class revenue responsibilities. She recommended an additional constraint that no customer class face an increase in excess of 1.5 times the system average increase. Nicholson at 23 and 25.

(3) IG Case-in-Chief. Mr. Phillips agreed that I&M's proposed rate design is reflective of cost and is appropriate, even though subsidies remain in the rate structure. Phillips at 4. He noted I&M's proposed method of distributing its requested rate increase to classes reduces existing interclass subsidies by 50% and moves rates closer to cost. *Id.* at 4 and 16. He suggested that another method would be to phase out subsidies until all existing interclass subsidies are reduced by 100%. To the extent I&M's proposed level of rate increase request is reduced, Mr. Phillips recommended consideration be given to moving rates even closer to cost of service than the 50% subsidy reduction proposed by I&M. *Id.* at 4 and 17.

(4) Commission Discussion and Findings. We agree with the parties that I&M's proposed method to reduce current interclass subsidies by 50% is a reasonable step toward cost-based rates and strikes the appropriate balance between progress toward eliminating interclass subsidies and a recognition of the rate impacts on the various tariff classes. We also find that the constraint recommended by Dr. Nicholson that no class face an increase in excess of 1.5 times the system average increase to be just, reasonable, and consistent with the principal of gradualism. This will ensure gradualism for all rate classes and reduce the possibility of any given class experiencing "rate shock."

**14. Rate Design.** The record reflects that, in general, the Company's approach is to design rates and rate components which reflect the underlying costs of the Company. Roush Direct, at 13. This includes collecting customer-related costs through customer charges and recognizing the differences in the costs to serve customers at different service delivery voltages. The record also reflects that as with the allocation of the revenue increases to the customer classes, the concept of gradualism was considered in the movement toward full cost- based rate components to avoid undue impacts on customers. The disputed rate design issues are discussed below.

**A. Voltage Differentiated Fuel Factors.**

(1) I&M Case-in-Chief. In Cause No. 38702 FAC 62 S1, the Commission approved a stipulation and settlement agreement which included a requirement that on or before October 31, 2011, the Company make a filing that provides both voltage differentiated fuel factors for customers served at secondary, primary, subtransmission and transmission voltages, and the uniform FAC factors that I&M typically files in each FAC case. Roush Direct, at 18. In its filing, the Company proposed to change the FAC base cost of fuel to 18.458 mills/kWh which is consistent with the uniform FAC factors that I&M typically files. *Id.* As explained by Mr. Roush, Petitioner's Exhibit DMR-2 presented the calculation of the FAC base cost of fuel by voltage based upon the energy sales data by delivery voltage and the energy loss analysis prepared in this proceeding. *Id.* He said sample calculations of fuel adjustment factors under such an approach are also presented in this exhibit. He stated that this information was provided to permit all parties to address issues and make specific recommendations to the Commission related to both the uniform and the voltage differentiated FAC rates.

(2) OUCC Case-in-Chief. The OUCC recommended that the Commission retain I&M's current uniform fuel factor. OUCC Witness Eckert testified that he is not conceptually opposed to voltage-differentiated FACs, but he does not believe sufficient detail has been provided--including a sample FAC application with supporting workpapers demonstrating how voltage delivery and energy losses would be utilized in a FAC proceeding--to advocate adoption by the Commission of the voltage-based FAC concept and presentation. Eckert at 15. Mr. Eckert also requested that the Commission allow the OUCC to file its testimony and report 35 days after I&M files its Application and testimony in its FAC proceedings. *Id.* at 16.

(3) IG Case-in-Chief. IG Witness Phillips testified that the fuel cost recovery mechanism will be more reflective of cost with a line-loss differentiated factor by rate class. He stated this method would extend the line-loss differentiated method commonly used and accepted in base rate design to all fuel cost recovery. He stated line-loss varies by voltage level of service and is a more cost reflective and accurate method of fuel cost recovery. Phillips at 19. He testified that in recognition of these cost differences, utility fuel costs in base rate cases are typically allocated using energy consumption adjusted to the source for line losses. He stated that although fuel cost in base rates reflects this allocation, fuel costs recovered through the FAC fails to recognize this difference in cost causation. He recommended the difference in fuel cost by classes due to voltage levels be addressed in the FAC proceeding and require a different fuel adjustment factor for each rate class reflecting the lower cost to serve high voltage customers in order to appropriately match the cost to serve to the customers causing the costs.

(4) SDI Case-in-Chief. SDI Witness Dennis W. Goins, PhD, of Potomac Management Group, recommended that recommend that the Commission approve the voltage-differentiated base fuel rates presented in I&M' s filing and that the Commission require I&M to submit future FAC filings that reflect voltage-differentiated fuel factors linked to voltage-differentiated FAC base rates approved in I&M's most recent general rate case. He asserted that the current use of a non-voltage-differentiated fuel charge forces high-voltage customers to subsidize low-voltage customers. He contended the subsidies are large, unfair, and unnecessary-problems that can be easily and justifiably mitigated by differentiating I&M's fuel factor by delivery voltage. Goins Direct, at 5.

In Cross-Answering Testimony, Mr. Goins responded to Mr. Eckert's recommendation to retain I&M's current uniform fuel factor, stating that Mr. Eckert's concerns are misplaced and the Commission has more than sufficient information in this case to set a voltage-differentiated fuel basing point for each of I&M's four principal voltage service levels. Goins Cross-Answering at 3-4.

(5) I&M Rebuttal. I&M Witness Krawec responded to Mr. Eckert's proposal to increase the amount of time for the OUCC to report on I&M's FAC filings. He suggested Mr. Eckert's testimony did not justify increasing the available days for the OUCC's report. He said I&M did not advocate a change to a voltage differentiated FAC but merely presented information on this concept. Even if a voltage differentiated FAC is adopted, Mr. Krawec claimed this adoption should not require additional time on the part of the OUCC for their FAC audit. Krawec Rebuttal, at 43-44.

(6) Commission Discussion and Findings. Petitioner has not requested a change to a voltage-differentiated FAC in this proceeding. The OUCC recommends against adoption of such a change at this time. Intervenors IG and SDI have advocated for the shift, stating that it is a more accurate matching of fuel cost and fuel cost recovery by customer class than the current method in FAC proceedings and should be implemented. I&M presented information on voltage differentiation in compliance with the stipulation and settlement agreement approved in Cause No. 38702 FAC 62 S1 in order to permit the parties to address issues and make specific recommendations to the Commission related to both the uniform and the voltage-differentiated FAC rates. We find that changing to a voltage-differentiated FAC would add, unnecessarily, complexity to the expedited FAC process without producing a material change in the outcome. Accordingly, we decline to adopt a voltage-differentiated FAC in this proceeding. Additionally, we find that, due to the complexity of Petitioner's FAC application, the OUCC shall heretofore file its testimony and report 35 days after I&M files its Application and testimony in its FAC proceedings.

**B. LGS Rate Schedule.**

(1) I&M Case-in-Chief. I&M Witness Roush testified that I&M was pleased with the success of the consolidation of Tariffs QP and IP into a single Tariff IP approved in its last basic rate case. He indicated that I&M believed a consolidation may ultimately make sense for Tariffs MGS and LGS, but that such a consolidation is too ambitious and expensive to achieve at this time given the differences in metering requirements and the power factor provisions. Roush Direct, 16. To promote the ultimate consolidation of these Tariffs, I&M proposed to incorporate a load factor blocking at 300 hours use per month into Tariff LGS to take the first steps towards a potential consolidation and also to provide LGS customers with the advantages that such a structure provides for customers whose load factor varies.

(2) Kroger Case-in-Chief. Kroger Witness Townsend recommended the Commission reject I&M's proposed redesign of the LGS rate schedule and instead require I&M to retain the same basic rate design for that rate schedule, while improving alignment between costs and charges by setting base demand charges for LGS Secondary and Primary at 65% of demand-related costs with a corresponding reduction in the base energy

charges to achieve the target revenue requirement for each LGS subclass. He also recommended that the base demand charges for LGS Subtransmission be set at 70% of demand-related costs with a corresponding reduction in the base energy charges to achieve the target revenue requirement for this subclass. Townsend at 3-4, 7.

(3) IG Cross-Answering Testimony. Mr. Phillips testified that Rate LGS should be designed to properly reflect demand and energy costs in the demand and energy components of the rate. Phillips Cross-Answering, 3. He stated that the LGS rates Mr. Townsend starts with still have subsidies in them and do not represent the actual costs resulting from the costs of service study. However, Mr. Phillips agreed that the LGS rate proposed by I&M should be modified to be more reflective of cost of service. *Id.* at 19.

(4) I&M Rebuttal. I&M Witness Roush disagreed with Mr. Townsend's characterization of I&M's changes to Tariff LGS as a radical redesign. He noted that such a redesign was already implemented for I&M's largest customers served under Tariff IP. I&M's redesign of Tariff LGS is designed to align it with Tariff IP, which contains a load factor block structure that is similar to the one being proposed for Tariff LGS. Mr. Roush explained the changes to Tariff LGS reflect I&M's experience with ongoing customer migrations between LGS and IP tariff classes and the potential future consolidation of Tariffs MGS and LGS. Roush Rebuttal, 13.

Mr. Roush explained that Mr. Townsend's proposal to maintain the current design is less favorable when all Tariff LGS customers are considered. He stated that a load factor based tariff structure, such as that adopted in I&M's proposed Tariff LGS, provides a better fit for customers across a range of usage characteristics and provides rate continuity for customers as customer usage changes. Mr. Townsend's proposal establishes a certain amount of demand costs to include in the demand charge and leaves the remainder included in energy charges resulting in winners and losers among the higher and lower load factor customers within that class, according to Mr. Roush. He noted that the impacts of Mr. Townsend's redesign are significantly higher on lower load factor customers than on higher load factor customers. Roush Rebuttal, 13-14.

Mr. Roush did propose a modification to the Tariff LGS rate design that more equally distributed the rate increase among lower and higher load factor LGS customers. He indicated that I&M is willing to adjust its proposed LGS rate design to reflect this modification. Roush Rebuttal, 14

(5) Commission Discussion and Findings. I&M has proposed to make modifications to Tariff LGS that better align the tariff with Tariff IP and reflects I&M's experience with ongoing customer migration between the two tariff classes. Mr. Townsend recommended Rate LGS be designed to better meet Kroger's needs. However, Mr. Townsend's proposal is unreasonable when all Tariff LGS customers are considered. The impacts of Mr. Townsend's redesign are significantly higher on lower load factor customers, who would face an increase of 16% to 17%, than on higher load factor customers, which would face an increase of only 6.3% to 8%. We find that Mr. Townsend's concerns are reasonably addressed by the tariff modifications proposed in Mr. Roush's rebuttal testimony. I&M Witness Roush's revisions more equally distribute the rate increase among lower and higher load factor LGS customers and result in rate continuity for customers as usage changes. Accordingly, we find I&M's modification to

the Tariff LGS described in Mr. Roush's rebuttal testimony should be approved. The methodology moderates the impact of the increase by spreading it out across all demand levels resulting in all LGS customers facing increases that range from 10.5% to 12.7%.

### C. Rate Adjustment Mechanisms.

(1) I&M Case-in-Chief. The Company proposed to maintain its existing rate adjustment mechanisms, including the PJM Cost Rider, Clean Coal Technology Rider ("CTTR") and Environmental Compliance Cost Recovery Rider ("ECCR") established in Cause No. 43306.

(2) OUCC Case-in-Chief. OUCC Witness Jasheway agreed with the continuing operation of the PJM Cost Rider as approved in Cause No. 43306, including maintaining the current level of PJM administrative costs in basic rates and the treatment of FTR revenues. Jasheway at 4, 11-12. He also agreed with I&M's proposal to incorporate credits resulting from FERC Docket No. ER09-1279 at the same time I&M implements new basic rates resulting from this Cause. *Id.* at 5.

(3) IG Case-in-Chief. IG Witness James R. Dauphinais, Principal of Brubaker & Associates, Inc., testified that he has no issue with I&M's proposal to return the Indiana jurisdictional portion of the retail ratemaking credits through the PJM Cost Rider. Dauphinais at 12.

(4) Commission Discussion and Findings. The parties are in agreement that the Retail Ratemaking Credits resulting from FERC Docket No. ER09-1279 should be included in Petitioner's PJM Cost Rider, and we concur. We find that the PJM Cost Rider should continue to operate as approved in Cause No. 43306, with the addition that the credits resulting from FERC Docket No. ER09-1279 shall also be included.

No parties filed testimony in opposition to Petitioner's proposal with respect to its CCTR or ECCR. We approve I&M's request to eliminate the amounts being collected in the CCTR associated with the pollution controls approved in Cause No. 43636 as of the effective date of new rates in this proceeding and I&M's proposed reconciliation in its next CCTR filing. We agree with I&M's proposal to use the CCTR for similar construction costs and operating expenses approved by this Commission. We find that I&M's ECCR and CCTR adjustment mechanisms shall continue as proposed by I&M. We address the OSS margin sharing mechanism in separate sections of this Order.

### D. Tariff, Rules and Regulations.

(1) I&M Case-in-Chief. I&M Witness William W. Hix, I&M Principal Regulatory Consultant - Regulatory Services Department, discussed the modifications to I&M's Terms and Conditions of Service and Tariffs. Hix Direct, at 2; Petitioner's Exhibit WWH-1. Mr. Hix said the proposed modifications are primarily due to either clarifying the existing term and condition or Company policy and that the clarifications will benefit customers by better explaining the Company's and the customer's obligations. *Id.* Mr. Hix indicated I&M's filing included the following tariff proposals.

(a) Equal Payment Plan ("EPP"). Mr. Hix said I&M included a proposal to limit the EPP to those customers currently enrolled under the plan. *Id.* at 3. Mr. Hix said that, based upon I&M's experience since the implementation of the Average Monthly Payment Plan ("AMPP") in Cause No. 43306, I&M has found that the AMPP payment plan provides a smoother and more consistent monthly payment than the EPP. *Id.* at 3-4. Mr. Hix reported that many EPP residential customers have encountered high bills to pay for their settlement month under the EPP. *Id.* at 4. He said the AMPP will eliminate these single monthly high bills and provide better consistency which is what most customers are seeking. *Id.*

(b) Dishonored Negotiable Instrument ("DNI"). Mr. Hix said the Company's proposal to increase the fee charged for a DNI received in payment for a bill rendered by the Company is needed to provide a more appropriate incentive to certain customers to not issue such an instrument. *Id.* at 4. He said I&M believes an increased fee from the current charge of $7 to $20 will not only put I&M more in line with Indiana's other investor owned utilities, but should also encourage a reduction in the number of such transactions which will benefit all customers. Mr. Hix said the revenue amount resulting from the proposed increase in the DNI charge of $51,966 is reflected in the Company's proposed revenue allocation as a reduction to the required basic rate increase as shown in Petitioner's Exhibit DMR-1 sponsored by Company Witness Roush.

(c) Reconnection Fee and Service and/or Disconnect and Reconnect Charge Rates. Mr. Hix said the Company added a fee for reconnections made at a pole on Sundays or holidays. *Id.* at 3. He said the addition of a Sunday and holidays' reconnection fee at a pole provides another option for reconnections that benefits those customers that might need such service. *Id.* at 4.

Mr. Hix said that, although the Company is not proposing an increase in the rates charged for Service and/or Disconnect and Reconnect Charges in this proceeding, per the Commission's Order in Cause No. 43306, these charges will increase on March 23, 2012. *Id.* at 5. He said the revenue impact of the approved Service and/or Disconnect and Reconnect Charge rates increases from Cause No. 43306 was estimated based on the number of transactions occurring during the test year. He said Operating Revenue Adjustment No. 15 of Petitioner's Exhibit A-5 increases I&M's Indiana jurisdictional operating revenues by $604,127 to reflect this increased revenue and that if this adjustment was not made, I&M's total company operating revenues would be understated. *Id.*

(d) Employee Rate for Tariff R.S. TOD2. Mr. Hix said I&M proposed to add an Employee Rate for Tariff R.S.-TOD2. *Id.* at 3. He said the Company expanded the availability of Tariff R.S.-T0D2 outside of the former South Bend Smart Meter Pilot Program area and neglected to propose an employee rate for this tariff and stated that expanding this offering to employees is appropriate and consistent with past practices. *Id.* at 4.

(e) Tariff Modifications and Additions. Mr. Hix said the proposed tariff book has been reorganized slightly to sequentially group tariffs that are similar, such as Tariffs IP, CS-IRP, and CS-IRP2. *Id.* at 5-6. He added that the rider tariff sheets have been grouped by non-surcharge and surcharge riders and a cover sheet for the surcharge riders was inserted to provide a convenient reference to all applicable surcharge riders. *Id.* at 6.

Mr. Hix said the Company believes the reorganization of the tariff sheets and the addition of the surcharge riders cover sheet will simplify reading the tariff book and in determining all applicable tariff rates. *Id.* Mr. Hix discussed the following proposed new tariffs, new tariff options and major modifications to tariffs:

(i) New Senior Citizen Tariff. Mr. Hix said I&M is proposing the addition of a residential tariff available to senior citizens. He said all residential customers, 65 years of age and head of household, are eligible for the proposed Tariff R.S.-SC. *Id.* at 5-6. Mr. Hix stated that I&M's most vulnerable customers are its fixed income senior citizens. For those qualifying senior citizens that are low usage (less than 1,000 kWh per month) customers, the proposed tariff offers them an opportunity to reduce their monthly electrical energy costs that they would otherwise see under Tariff R.S. *Id.* at 6. He noted that Company Witness Roush discussed the rate design for the proposed tariff.

(ii) New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage). Mr. Hix said I&M's approved Tariff R.S.-OPES is currently available to customers who use energy storage devices with time-differentiated load characteristics such as electric thermal storage space-heating equipment and water heaters which consume electrical energy primarily during off-peak hours. *Id.* at 7. He reported that I&M is planning to begin an evaluation of customer utilization of Plug-in Electric Vehicles ("PEVs") throughout its Indiana electric service territory and specifically, the operational impacts of charging PEVs, the benefits of utilizing off-peak charging of PEVs and the associated infrastructure requirements. *Id.* He said that, to assist with this evaluation, I&M is proposing to rename its current Tariff R.S.- OPES to Tariff R.S.-OPES/PEV (Residential Off-Peak Energy Storage/Plug-In Electric Vehicle) and include a voluntary optional provision for PEV charging stations programmed to consume electrical energy primarily during off-peak hours, as equipment qualifying customers to receive service under the tariff. *Id.*

Mr. Hix said I&M's proposed Tariff R.S.-OPES/PEV includes an Experimental Electrical Vehicle Supply Equipment ("EVSE") Option where the Company will reimburse up to $2,500 toward the purchase of Company approved PEV supply equipment. *Id.* at 7-8. PEV supply equipment is defined in the proposed Tariff as the charging station including conductors, the ungrounded, grounded, and equipment outlets, or apparatus installed specifically for the purpose of delivering electric energy from the premises wiring to the PEV, if not otherwise provided, and installation costs of a separately metered circuit. *Id.* at 8. Mr. Hix said the Company benefits from the collection of separately metered PEV usage through this provision. *Id.* He said although the reimbursement option will be made available to the first 250 qualifying customers that properly apply for such option, there is no limit in the number of customers that may receive service under Tariff R.S.-OPES/PEV. He concluded this part of his testimony by suggesting the proposed terms and conditions of service are reasonable and the rates under the Tariff for a PEV customer are not different from the rates proposed for all other Tariff R.S.-OPES/PEV customers. *Id.*

Mr. Hix said I&M requests the Commission approve the revised Tariff R.S.-OPES/PEV and authorize, for ratemaking purposes, the deferred recovery of the expenses incurred for the EVSE Option. *Id.* He said the total amount deferred is limited to the maximum per customer reimbursement amount ($2,500) and the maximum number of eligible customers (250) for a total of $625,000 and that the deferral period of this expense would be from the time the revised Tariff R.S.-OPES/PEV is approved by the Commission until the expense is included in a subsequent general rate case. *Id.* Mr. Hix said the Company also requests the assured recovery of the deferral of costs through the recordation of a regulatory asset and the Company will include the amortization of this asset in a subsequent general rate case. *Id.*

(iii) Tariff O.L. (Outdoor Lighting). Mr. Hix said I&M currently provides the post-top lamp under its street lighting tariff but it is not currently available under Tariff O.L. *Id.* at 9. He said the addition of a post-top lamp to Tariff O.L. is needed to address the frequent requests for such lamps. *Id.* He also stated that the customers requesting this post-top lamp are typically not eligible for service under the streetlight tariff. *Id.*

(iv) Tariff S.G.S. (Small General Services) and M.G.S. (Medium General Services) Consolidation. Mr. Hix said I&M is proposing a consolidation of Tariffs S.G.S. (Small General Service) and M.G.S. (Medium General Service) into one tariff (Tariff G.S.). *Id.* at 6, 9. The introduction of Tariff G.S. will also require canceling Tariffs S.G.S. and M.G.S. Mr. Hix suggested that consolidating the two tariffs (S.G.S. and M.G.S.) into one tariff will benefit those customers whose usage varies such that some months of the year they would be better off receiving service under Tariff S.G.S. and some months of the year under Tariff M.G.S. *Id.* at 9. He alleged those customers that do not fall into this category will basically see little if any real change from their current billing other than the proposed increases in rates that they would otherwise be seeing as a result of this Cause. *Id.*

Mr. Hix said the consolidation of Tariffs S.G.S and M.G.S. will prompt the need to rename Tariffs S.G.S.-TOD and M.G.S.-TOD to G.S.-TOD2 and G.S.-TOD, respectively *Id.* Due to its association with proposed Tariff G.S., Tariff G.S.-TOD will be expanded to include secondary and primary service offerings and the lower availability threshold will be reduced from 10 kW to zero kW. *Id.* at 9-10. Mr. Hix said that by consolidating the two tariffs into one tariff, the Company will be positioned to provide better customer service and management of the customers qualifying for the new consolidated tariff. *Id.* at 10. Company Witness Roush explained the rate design for the proposed consolidated tariff.

(v) Tariff L.G.S. (Large General Services) Modification. Mr. Hix said the Company is proposing to implement in I&M's existing Tariff L.G.S. (Large General Service), a load factor blocking that mirrors the load factor relationship contained in Tariff I.P. (Industrial Power). *Id.* at 10. He suggested the implementation of this mechanism will provide a better transition for those customers that become ineligible for Tariff L.G.S. and must migrate to Tariff I.P., and for those Tariff I.P. customers that may benefit from a migration to Tariff L.G.S. Company Witness Roush explained the rate design for this proposal. *Id.*

(vi) Additional Tariff and Rider Modifications or Language Changes. Mr. Hix said the Company is proposing an additional provision to Tariff E.C.L.S. (Energy Conservation Lighting Service) to address those rare instances when customers request the removal and/or relocation of lamps. *Id.* The proposed revision reflects the Company's terms and conditions regarding such customer requests to remove and/or relocate Company facilities while also addressing issues that may arise in fulfilling such requests that involve streetlights. *Id.* Mr. Hix alleged the addition of the provision provides customers with a clear and concise expectation when considering making such requests for the removal and/or relocation of Company facilities that provide streetlight service. *Id.* at 10-11. He said the Company is proposing an increase in the amount of discount a customer qualifying for an Economic Development Rider ("EDR") would receive. *Id.* at 11. Mr. Hix said the current discount is based on a percentage of the Tariff I.P. (Industrial Power) demand charge. *Id.* He said in Cause No. 43306, the EDR was renewed with only slight modifications after having been expired for several years. *Id.* Mr. Hix noted that, in Cause No. 43306, Tariff I.P. was redesigned such that the demand charges were reduced by approximately 200-300 percent. *Id.* he said the unintended consequence of this approved change to Tariff I.P. was that on a dollar for dollar basis, the EDR discount offered today is considerably less than the EDR discount that was offered several years ago. *Id.* Mr. Hix alleged an increase in the EDR discount percentage as proposed will put the EDR discount more on par with the level of EDR discounts from several years ago as well as help to incent customers to locate and expand in I&M's service territory. *Id.*

Mr. Hix discussed the Company's proposed clarifying language to Rider AFS (Alternate Feed Service). *Id.* Rider AFS approved in Cause No. 43306 currently indicates that the rider is applicable to those customers requesting new or upgraded AFS and those customers provided AFS under an approved contract. *Id.* Mr. Hix reported that, since the rider's approval on March 4, 2009, all issues regarding customers under a previously approved contract have been addressed. *Id.* Mr. Hix said the word "upgrade" has caused some confusion and that the proposed wording clarifies that an upgrade refers to a required expenditure by the Company in order to continue providing an existing AFS that is not under contract. *Id.* at 12. He suggested the clarifying language does not change any approved provisions or applications of Rider AFS but is intended to better explain those provisions. *Id.*

(vii) <u>Closing or Cancelled Current Tariffs or Riders.</u> Mr. Hix discussed I&M's proposal to close or cancel Tariff E.H.S. (Electric Heating Schools), and Riders ECS (Emergency Curtailable Service) and EPCS (Emergency Price Curtailable Service). *Id.* at 12. He said Tariff E.H.S. was established in the early 1970's and made available to "primary and secondary schools and to college and university buildings, and additions thereto, where the principal energy requirements, including all lighting, heating, cooling, water heating, and cooking, are provided by electric energy" and stated that Tariff E.H.S. was closed to new business as of April 6, 1981. *Id.* Over the thirty plus years since the tariff was closed to new business, most of the customers served under this tariff have migrated to other more appropriate tariffs, leaving a small number of accounts remaining on Tariff E.H.S. In addition to the fact that there are only a small number of accounts remaining on Tariff E.H.S., the Company is proposing closing this tariff to all business due to the time and difficulty in verifying that customers continue to qualify for the tariff. *Id.* Mr. Hix said Tariff E.H.S. is an energy billing (kWh) only tariff; therefore there is no customer price signal to control their electrical demand which is inconsistent with I&M's DSM/EE concepts. *Id* at 12-13. He said because this tariff is closed to new business, with only a select few customers qualifying, other similar customers are currently being treated inconsistently. *Id.* at 13. While there are similar issues today for Tariffs E.H.G. (Electric Heating General) and M.S. (Municipal and School Service), the number of customers served under those tariffs and associated costs of meter replacements is too high to warrant eliminating those tariffs at this time. Riders D.R.S.1 and D.R.S.2 were approved in Cause No. 43566 PJM1 on April 27, 2011 and May 18, 2011, respectively. With the approval and implementation of these two riders, and the lack of customer interest shown in Riders ECS and EPCS, the Company believes that Riders ECS and EPCS should be closed. Although Riders ECS and EPCS have essentially existed for more than twelve (12) years, no customers have ever committed to any curtailments under the riders; therefore, Mr. Hix said it is appropriate to close these riders at this time. *Id.*

(2) OUCC Case-in-Chief. Mr. Eric M. Hand and Mr. Ron Keen, OUCC Utility Analysts, presented their concerns and recommendations regarding the following issues:

- The potential financial risk to senior citizens if the Commission approves I&M's proposed Optional Residential Senior Citizen Rate (I&M Tariff RS-SC);

- I&M's practice of requiring ratepayers to fund special electric utility service discounts for I&M employees;

- Tariff provisions that create an inadequate and flawed process for obtaining Commission approval of Special Contracts;

- Tariff provisions that inappropriately shift responsibility to captive ratepayers for damages caused by I&M service deficiencies (Terms and Conditions 11 and 12);

- Proposed tariff changes that would inappropriately erode a customer/landowner's right to participate in decisions concerning the placement of utility equipment or facilities on customer-owned property; and

- Tariff provisions that would unnecessarily expand I&M's ability to disconnect service without prior customer notice.

- Tariff providing for a new Plug-In Electric Vehicle ("PEV") program without adequate opportunity for all interested parties to participate in its development.

(a) New Senior Citizen Tariff. Attachment EMH-1 to Mr. Hand's testimony summarized the differences between I&M's standard residential rate and I&M's proposed Senior Citizen Rate, which is an inverted rate. With inverted rates, the per kWh Energy Charge increases with the volume of electricity used. Mr. Hand testified that under the Senior Citizen Rate, the proposed energy charge for the first 500 kWh each month are priced about two cents below the standard residential rate, while all kWh above 500 are priced two cents above that rate. With usage of 1000 kWh per month, the assumed average usage per month, the total amount billed would be identical under the proposed Senior Citizen Rate and I&M's standard residential rate. Mr. Hand observed the Senior Citizen Rate provides a variable financial reward for customers who are able to keep energy usage below 1,000 kWh per month. To achieve the maximum benefit ($10.16/month), customers would have to use exactly 500 kWh per month. Using less than 500 kWh reduces the customer's overall monthly bill, but also reduces Energy Charge savings. Conversely, as usage levels increase above 500 kWh, potential savings would still be realized, but would continue to decrease until usage reached 1,000 kWh per month, at which time the amount billed under the Senior Citizen Rate would equal the amount billed under the standard residential rate. Hand, at 3.

Mr. Hand emphasized that under the Senior Citizen Rate, customers using more than 1,000 kWh per month would incur a "penalty," because total charges under the Senior Citizen Rate would exceed total charges under the standard Residential Service Rate. Mr. Hand was concerned seniors would face financial risks if they did not understand that the proposed discounted Senior Citizen Rate comes with conditions. *Id.* at 4. It is imperative to understand the discount can disappear completely and, for every month when usage exceeds 1000 kWh, the total amount billed under the Senior Citizen Rate would exceed the amount that would have been billed under the standard residential tariff. Mr. Hand was also concerned about the lack of a cap on the number of kWh that can be charged at the higher rate, if monthly consumption exceeds 1000 kWh. Mr. Hand also took issue with I&M's plan to lock participating customers into the Senior Citizen Rate for a full year. *Id.* Because there is no cap on the number of monthly kWh billed at the higher rate, the Senior Citizen Rate could ultimately provide a net financial gain for I&M, at the expense of "I&M's most vulnerable customers...its fixed income senior citizens." *Id.*.

Mr. Hand questioned I&M's claim that its proposed Senior Citizen Rate is designed to be revenue neutral. He observed that I&M's response to OUCC's discovery requests (Q21-2h) demonstrated a lack of sufficient data to support that claim. Mr. Hand indicated I&M did not know how many customers would be eligible for the Senior Citizen Rate and had no data from which to calculate its Indiana senior citizen customers' average monthly usage. He therefore questioned how I&M could claim revenue neutrality, given the absence of basic data needed to make such a determination. *Id.* at 4-5.

Mr. Hand explained the OUCC was not opposed to offering seniors (or any other customers) an opportunity to proactively and responsibly reduce their electric bills. However, he could not support I&M's proposed Optional Senior Citizen Rate as currently presented. He also expressed concern that senior citizens could mistakenly believe that a "Senior Citizen Rate" would include a guaranteed discount for elderly consumers, given the current widespread availability of senior discounts. *Id.* at 5. Mr. Hand recommended the Commission reject I&M's request for approval of the Senior Citizen Rate; or, if approved, require I&M to work with the OUCC to develop the following:

- Promotional materials that fully disclose the potential risks as well as the potential benefits to participating senior citizens;

- Mutually acceptable safeguards that would permit seniors to leave the program after less than one year, while also balancing I&M's need to prevent customers from gaming the system; and

- An agreed format for an annual report detailing customer participation, complaints, sales volumes under the tariff, and other important data.

*Id.*

(b) Employee Discounts. Mr. Hand testified that ratepayers should not be required to fund special discounts for utility employees, as I&M's residential customers currently do. Mr. Hand noted I&M's case-in-chief included testimony concerning the comprehensive corporate belt-tightening used to help postpone the need for filing this rate case. He observed that I&M did not take the opportunity to eliminate ratepayer-funded employee discounts, an approach that could have helped reduce the magnitude of I&M's proposed rate increase. Mr. Hand indicated if utility management decides to include utility service discounts in its employee benefit packages, it should be able to do so; but, funding for such discounts should come from shareholders, not from other customers. Mr. Hand felt strongly that managers of monopoly utilities should not be permitted to use captive ratepayer dollars to fund service discounts for themselves and other utility employees. Mr. Hand also stated the expectation that utility managers and employees will have to pay the same utility rates their customers pay provides some additional incentive to management to keep rate increases as low as reasonably possible. *Id.* at 6.

(c) Tariff C.S.-IRP and Tariff C.S.-IRP2. Mr. Hand testified that requests for approval of special contracts or any other documents for which I&M is seeking confidential treatment and protection from public disclosure should not be accepted as 30-day filings. He commented that language in Original Sheet No. 17 of I&M Tariff C.S.-IRP (Contract Service Interruptible Power) allows the Company to file special contracts with unique discounts for certain customers under the Commission's 30-day filing process. Mr. Hand recommended that portion of the tariff be removed since it does not serve the public interest. Mr. Hand turned to 170 IAC 1-6 for the rules governing 30-day filings before the Commission. Section 4 of that rule lists prohibited filings and Subsection (8) prohibits use of the 30-day filing process to gain approval of "any filing for which the utility wants confidential treatment for all or part of the filing." Since virtually all special contracts provide special discounts to some, but not all utility customers, utilities routinely request this information and other terms and conditions of the contract, be treated as confidential. *Id.* at 7.

Mr. Hand testified that Title 170 IAC 1-6-3 lists allowable 30-day filings. He expressed concern that Subsection (6) provides a potential exception for I&M to attempt to avoid the rule's clear prohibition against the inclusion of confidential information in a 30-day filing. The language that troubled Mr. Hand reads as follows, "A filing for which the commission has already approved or accepted the procedure for the change." It would not serve the public interest to interpret Tariff C.S.-IRP as including language designed to circumvent the unambiguous prohibition on the submission of confidential materials in 30-day filings. The 30-day filing process is only to be used for "noncontroversial" submissions (170 IAC 1-6-1(b)). Controversy in potential interclass rate subsidies, the amount of the discount, the terms and conditions of the contract (interruptible credits, for example) can easily become controversial. Mr. Hand therefore recommended the Commission remove the phrase "under the 30-day filing procedures" from Tariff C.S.-IRP (Pet. Ex. WWH-2, Page 40 of 138, Original Sheet No. 17 and Pet. Ex. WWH-2, Page 42 of 138, Original Sheet No. 18) and from any other sections of I&M's tariff. *Id.* at 7-8.

(d) Tariff Terms and Conditions 11 and 12. Mr. Hand also expressed concern that certain language in Tariff Term and Condition ("T&C") 11, "Company Liability", and proposed for T&C 12, "Customer Liability", would unfairly shift additional financial liability for service deficiencies onto I&M's ratepayers. *Id.* at 8. The disputed provision reads as follows:

The customer shall provide and maintain suitable protective devices on customer-owned equipment to prevent any loss, injury, or damage that might result from single-phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury, or damage resulting from a single-phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices.

Mr. Hand testified the above language could be used by I&M to attempt to shift additional risks and responsibilities onto its customers. The language provides no meaningful guidance to consumers, who generally do not claim to be experts in electric safety. Mr. Hand noted customers reasonably expect I&M to fulfill its assigned duty to provide safe and reliable electric utility service as a regulated public utility. Mr. Hand argued that I&M's attempt to escape liability in that manner is inconsistent with testimony in I&M's Case-in-Chief, praising the utility's own safety record. Given I&M's statutory duties as a public utility and its superior knowledge of the design and operation of electric utility systems, I&M's customers should not be asked to shoulder responsibility for protecting themselves, their families and their homes from damage, injury or loss if the utility fails to meet its duty to provide safe and reliable electric utility service to the public. The OUCC therefore requested the proposed addition to T&C 12 be denied and that the language be removed from T&C 11. *Id.* at 8-9.

(e) Tariff Term and Condition 16. Mr. Hand testified he considered I&M's proposed change to Tariff T&C 16 an erosion of customer/landowner rights to participate in decisions regarding the placement of utility equipment or facilities on their privately owned property. Mr. Hand took issue with I&M's proposed insertion of the clause, "[as] specified by the Company" in T&C 15. He noted the language- would give I&M unilateral control over decisions on where to place facilities and equipment on private property. *Id.* at 9. The OUCC recommended the Commission to reject the above language outright.

(f) Tariff Terms and Conditions 12 and 17. Mr. Hand also challenged I&M's proposed insertion of the following language in Tariff T&Cs 12 and 17:

The Company may disconnect service without request by the customer and without prior notice if in the Company's sole judgment the customer's continued service will be detrimental to the Company's general service.

Mr. Hand observed the above language was overly broad and, if approved, would unnecessarily increase the utility's current ability to disconnect service without providing prior customer notice. T&C 5 on "Denial or Discontinuance of Service" already contains two pages of specific instances in which service can be terminated, including disconnection without prior customer notice. He also expressed concern that there was no indication that the current language in T&Cs 11, 12 and 17 did not adequately protect I&M without the addition of the additional proposed language in T&Cs 12 and 17. Accordingly, the OUCC urged the Commission to reject the proposed language for insufficiency of evidence to support the need for such a broad expansion of T&Cs 12 and 17 which address service disconnect without advance notice. *Id.* at 10.

(g) New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage). OUCC Witness Keen testified as to the OUCC's concerns regarding I&M's proposed Plug-In Electric Vehicle ("PEV") program under new Tariff R.S. – OPES/PEV. Mr. Keen objected that until it was offered as a new tariff in this Cause, the OUCC had not seen any formal presentation of this concept to the Commission or any other agency. Consequently, Mr. Keen stated, there had been little opportunity to explore the proposed program other than what has been presented in the docket by I&M or gathered through discovery. Keen Direct, at 28. Mr. Keen testified the OUCC supports the development and integration of electric vehicle technology into society and that the clear benefit electric vehicle technology offers to the United States in a number of areas, including energy independence, is unequivocal. *Id.* at 29. However, Mr. Keen stated that, unfortunately, the OUCC lacks sufficient information on I&M's program and is concerned there are serious deficiencies and flaws in the proposal including (1) the use of the term "Experimental," (2) how I&M defines and categorizes Electrical Vehicle Support Equipment ("EVSE") and (3) a potential requirement that only specific PEVs can participate in the program. Keen at 29.

Mr. Keen explained that, to a lay person, the term "experimental" implies a limited lifespan – a period of time to gather data and conduct certain procedures to validate processes. Mr. Keen stated I&M's response to an OUCC data request states that the program has no designated termination date and, in fact, I&M claims the Tariff R.S.-OPES/REV and the proposed addition of PEV charging to qualify for the tariff are not experimental. According to I&M, Mr. Keen explained, only the addition of the Electric Vehicle Support Equipment option is "experimental." Furthermore, Mr. Keen explained that I&M stated in an additional response the program is not a pilot program. *Id.* at 29-30.

Mr. Keen also testified the OUCC has concerns regarding how I&M defines "charging stations" as first referenced in the initial paragraph of the proposed tariff. Mr. Keen explained that while it would appear the definition of EVSE is relatively benign and inclusive, he believed a customer might not know exactly what is allowed or prohibited. *Id.* at 30-31. Mr. Keen explained that I&M does not currently maintain a list of Company approved PEV charging devices, but that the company was performing tests on a number of chargers available on the market. Mr. Keen then testified that the criteria for approved equipment had not yet been developed by I&M and that the OUCC believes I&M is asking the Commission to approve a tariff which requires customers to use Company-approved EVSE to qualify for the reimbursement, but has no guidelines to help customers determine what actually qualifies. *Id.* at 31-32.

Mr. Keen testified that the requirement to install Level II Electric Vehicle Support Equipment is not contained in the proposed tariff, nor is there language in the proposed tariff which would specifically limit the EVSE qualifying for reimbursement to Level II equipment. Mr. Keen further testified it is also not clear as a requirement, nor is the term "Level II EVSE" even used in the copy of the contract I&M provided to the OUCC. *Id.* at 32-33. Mr. Keen testified that it is not clear from either the language contained in the tariff or in the contract how I&M intends to collect data from the meters, or what types of specific data points would be collected and for what purposes the data would be used. *Id.* at 33. Mr. Keen further testified there is no language in the proposed tariff or the contract supplied to the OUCC which specifically mandates Level II EVSE be installed to receive the reimbursement and that he could see nothing in the tariff or contract language as it has been presented in this Cause which would prohibit a customer from installing a dedicated Level I charging circuit or even a Level III charger to qualify for the $2,500 reimbursement of expenses. *Id.* at 34. Mr. Keen indicated that tariffs should avoid hidden requirements that ordinary customers could not reasonably be expected to anticipate and recommended I&M change the language of the tariff and/or contract specifying that the reimbursement is only applicable to the installation of Level II EVSE on the customer premises in terminology a typical lay-person will understand. *Id.* at 34-35.

Mr. Keen also testified the term "SAE J1772" does not appear in either the proposed tariff contained in Exhibit WWH-8 or in the sample contract offered to the OUCC, but that the proposed tariff does define a qualifying plug-in electric vehicle as "plug-in electric vehicles registered and operable on public highways in the State of Indiana," and the sample contract goes a step further by defining qualifying vehicles as "registered Plug-in Electric Vehicle (including Plug-in Hybrid Electric Vehicle (PHEV), Battery Electric Vehicle (BEV) & Extended Range Electric Vehicle (EREV)) in the State of Indiana." *Id.* at 35-36. Mr. Keen then expressed concerns that a customer could justifiably arrive at the erroneous conclusion that any plug-in electric vehicle should qualify, including older models which do not use the J1772 plug (since it was not developed at the time) or those electric vehicles developed as "home builts" or "conversions." *Id.* at 36. Mr. Keen continued by stating that the hidden standard imposed by I&M would prohibit any new future technology which might come out which is not J1772-compatible. *Id.* Mr. Keen offered the example of inductive charging, which does not use a J1772 connector or any connector but is nevertheless available today. Mr. Keen indicated that the load requirement for an inductive charger could still be monitored and measured. *Id.*

Although Mr. Keen offered various suggestions for improving I&M's proposals, he concluded this portion of his testimony by describing how PEV integration into the grid involves not just off-peak charging and rates, but also more far-reaching concerns including grid robustness, increased energy demand, and Level II/III charging infrastructure support. Therefore, Mr. Keen indicated that the OUCC would prefer that I&M's proposals be considered in a separately docketed proceeding, to provide an opportunity for it to be fully vetted and discussed by all interested parties. *Id.* at 37.

To summarize, the OUCC recommended the Commission take the following actions to protect I&M's customers:

- Deny I&M's request for approval of its proposed Optional Residential Senior Citizen Rate. If the Commission approves the rate, it should impose additional conditions to protect the interests of participating senior customers.

- Deny recovery from ratepayers of I&M employee discounts on electric utility service.

- Require I&M to remove certain language from the terms and conditions of Tariff C.S.-IRP, C.S.-IRP-2, and any other I&M tariffs, if the language purports to allow information submitted under the Commission's streamlined 30-day filing process to be treated as confidential and protected from public disclosure;.

- Reject proposed tariff language assigning liability for service deficiencies to I&M's captive customers.

- Reject I&M's attempt to erode customer/landowners' rights to participate in decisions regarding the placement of utility facilities or equipment on private property.

- Deny I&M's request for additional discretion to disconnect electric utility service without providing advance notice to customers.

- Reject I&M's proposed Plug-In Electric Vehicle ("PEV") program.

(3) IG Case-in-Chief. IG Witness Dauphinais opposed I&M's proposed new terms and conditions for non-residential customer deposits in Rule 4 of its Terms and Conditions of Service. He characterized the proposed provisions as "too draconian" for non-residential customers and stated they give too much discretion to the Company. Dauphinais at 8. He also asserted that the proposed provisions are inconsistent with past Commission orders regarding electric utility customer deposits. *Id.* at 8-9. Mr. Dauphinais recommended that the non-residential customer portion of the Company's proposed Rule 4 be predicated on the assumption that new applicants and existing customers are creditworthy, and that a security deposit should only be required where a lack of creditworthiness is determined through payment delinquency or verifiable conditions demonstrating potential insolvency. *Id.* at 9. He further recommended that it incorporate the protections to which residential customers are entitled under 170 IAC 5-1-15. Those protections include: (a) written notice of the precise facts upon which the Company bases its decision; (b) an opportunity to rebut those facts and appeal the Company's determination; (c) payment of interest at a rate commensurate with the length of withholding; and (d) review of the basis upon which any deposit is withheld on a periodic basis, not to exceed twenty-four (24) months, and refund upon the determination of creditworthiness. He stated it should also minimize the discretion given to the Company to better ensure an equitable and non-discriminatory determination of customer creditworthiness. Finally, Mr. Dauphinais testified that in all instances where a security deposit is required, a letter of credit should be permitted as an alternative to a cash deposit. *Id.* at 10.

(4) I&M Rebuttal In its rebuttal testimony, I&M discussed each of the following issues:

(a) Employee Discounts. I&M Witness Chodak discussed the OUCC's recommendation to disallow a long-standing employee discount. He said the employee discount is a modest part of I&M's overall remuneration package and, as a tax-free fringe benefit, costs less from a ratemaking perspective than alternative forms of compensation. He suggested I&M regularly benchmarks its total compensation and it is commensurate with the Company's peers. Chodak Rebuttal, at 5.

(b) New Senior Citizen Tariff. Mr. Hix discussed Mr. Hand's concerns regarding the proposed Optional Senior Citizen Tariff. He said I&M has successfully offered a similarly structured tariff in its Michigan jurisdiction for more than 30 years. He said I&M found this new optional tariff offering was quite popular with many senior citizens in the former Three Rivers Rate Area in Michigan after it was offered there in 2010. He indicated that this popularity in Michigan, along with a desire to assist I&M's most vulnerable customers, prompted I&M to make a similar offering in this proceeding for its Indiana senior citizens. He said I&M is well versed in explaining to customers how the tariff works and the potential for higher monthly bills should they exceed 1,000 kWh during a billing period. He said very few issues have arisen with respect to the senior citizen tariff in Michigan, and all of the issues were satisfactorily resolved. Hix Rebuttal, at 3.

Regarding Witness Hand's concern that customers choosing service under this optional tariff are locked in for one year, Mr. Hix said this provision reflects I&M's general policy with regard to tariff migrations (see T&C 1). However, to alleviate the OUCC's concern that customers who choose the optional tariff are "locked in for one year," I&M proposed a modification to the proposed tariff. The proposed change would allow customers who migrate to the tariff and wish to return to another residential tariff in less than one year to do so. However, they must remain at the tariff that they migrate to for a minimum of twelve months. *Id.* at 4; *see* Petitioner's Exhibit WWH-R1.

Mr. Hix discussed I&M Witness Roush's testimony regarding the revenue neutrality of Tariff R.S.-SC, indicating that it was designed to be revenue neutral in the sense that a customer consuming 1,000 kWh in a billing period (the average monthly usage by a residential customer) would pay the same amount under either Tariff R.S.-SC or the standard residential tariff. Hix Rebuttal, at 4-5. It is true I&M does not know how many customers may opt for service under the proposed optional tariff. But Mr. Hix said it is reasonable to expect that only those customers who would realize a net benefit will do so. He said the Company expects that implementing Tariff R.S.-SC will result in a reduction of revenue, rather than an increase in revenue, as projected by OUCC witness, Mr. Hand. *Id.* at 5. Mr. Hix said the potential loss of revenue resulting from Tariff R.S.-SC is not reflected in I&M's cost of service analysis. *Id.*

Mr. Hix disagreed with Mr. Hand's recommendation that I&M work with the OUCC to develop promotional material and customer safeguards regarding the proposed Tariff R.S.-SC as well as an annual reporting requirement. He said the proposed tariff with the slight modification mentioned above should alleviate the OUCC's concerns that I&M's senior citizens may be confused about how the proposed tariff works until after they are "locked-in" to the tariff for a whole year. Mr. Hix said there is no reason to delay I&M's senior citizens access to the proposed discounted tariff or to impose the additional cost of producing an annual progress report. Mr. Hix noted that I&M meets with the OUCC from time to time and has no objection to responding to OUCC questions on an informal basis. He said the informal approach would still keep the OUCC informed on I&M's progress implementing this optional tariff. He said I&M would provide reasonable information, such as participation levels, usage and revenues, without the need for an additional reporting requirement. *Id.* at 5-6.

(c) Tariff Terms and Conditions 11 and 12. Mr. Hix discussed Mr. Hand's recommendation to remove language from Terms and Conditions 11 and 12. He described the language at issue, which establishes the customer's responsibility to provide and maintain suitable protective devices on customer-owned equipment. Mr. Hix said the purpose of including this language in Term and Condition 12 is to provide additional clarity and transparency for I&M's customers, not to impose additional risks or responsibilities onto any customers. He said the language that requires customers to be responsible for maintaining suitable protective devices due to fluctuations or irregular supplies of energy is standard in the electric utility industry and has not been a source of complaints or concerns raised by I&M customers in this proceeding. *Id.* at 6-7.

(d) Tariff Term and Condition 16. Mr. Hix said the proposed language in Term and Condition 16 was intended to clarify a longstanding provision that the utility has final say in the location of the facilities required to provide service to the customer and is essentially a reiteration of the same provisions included in Term and Condition 9. *Id.* at 7-8. He said this provision is standard in the electric utility industry. He suggested that I&M employs good engineering practices at the lowest reasonable cost when it plans service extensions.

(e) Tariff Terms and Conditions 12 and 17. With respect to I&M's proposal to add clarifying language to Terms and Conditions 12 and 17 regarding disconnection of service, Mr. Hix said this language was intended to clarify that I&M may disconnect a customer in the event their service is detrimentally affecting I&M's general service. *Id.* at 9. He said the proposed language is to ensure all of I&M's customers continue to receive adequate, safe and reliable electric service. He said the existing language from Term and Condition 17 was intended to clarify that customers may not use equipment in such a manner as to interfere with I&M's responsibility to supply service to its other customers. Mr. Hix said the need for an immediate disconnection, without notice, would be a rare circumstance, but could be necessary under certain circumstances. For example, immediate disconnection could be required if a customer's equipment that is experiencing catastrophic failures (such as a failure of an arc furnace or damaged customer owned distribution equipment) could damage I&M's system. *Id.*

(f) Tariff C.S.-IRP and Tariff C.S.-IRP2. Mr. Hix suggested the issue of Mr. Hand's recommended removal of the Commission approved language in Tariffs C.S.-IRP and C.S.-IRP2 regarding "30-day filing procedures" was fully litigated in Cause No. 43878. He complained that it is not necessary to re-litigate this issue and Mr. Hand's recommendation should be rejected. *Id.* at 11-12.

(g) New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage). I&M offered revisions to the proposed language of Tariff R.S.-OPES/PEV to alleviate the OUCC's concerns raised in Mr. Keen's testimony. Specifically, with regard to the EVSE Option language, I&M suggested replacing "Company approved" with "UL Certified SAE J1772 compliant Level II." *Id.* at 15. Mr. Hix said similar language would also be added to the contract required for those customers choosing the EVSE Option. *Id.*; *see* Petitioner's Exhibit WWH-R2. I&M also agreed with Mr. Keen that the tariff language should better identify qualifying PEVs in the Availability Statement of the tariff. I&M suggested that the following statement be added to the end of the first paragraph of the Availability of Service statement: "For purposes of service under this tariff, a qualifying PEV is any SAE J1772 compliant motor vehicle registered to operate on public highways in the State of Indiana and is propelled by an electric motor and batteries that can be charged by an external source of electricity." Hix Rebuttal, at 17; Petitioner's Exhibit WWH-R2.

In response to Mr. Keen's concern with the use of the term "experimental" in the title of the EVSE option, Mr. Hix said the EVSE option is designed to allow I&M to gather data. He said I&M does not currently know when the Company will have obtained sufficient load research data to warrant termination of the EVSE Option. Hix Rebuttal, at 14. Regarding Mr. Keen's concern that "there is no way to determine whether this tariff will last for a day, a week, months or years," (Keen Direct, at 30), Mr. Hix said the fact that at some point in the future the $2,500 incentive may come to an end in no way harms any customer who have already invested in a PEV charging station or a PEV. He suggested proposed Tariff R.S.-OPES/PEV can exist and provide a lower cost off-peak energy option to PEV and/or PEV charging station owners with or without the EVSE Option. *Id.* at 14-15. Mr. Hix said that, to his knowledge, the concern noted by the OUCC has not arisen among the approximate 750 Indiana customers who have already invested in ETS equipment. Given this, he claimed it would not be necessary to take a different view of the tariff with the addition of PEV charging stations as equipment qualifying for service under the tariff. *Id.* at 15.

Mr. Hix said it is not clear to I&M what the OUCC's concern is regarding the collection and use of PEV charging station usage data. He described the proposed tariff language and claimed PEV charging station load research data will be obtained and processed in the same manner that I&M currently obtains and processes its other load research program data. *Id.* at 16. Mr. Hix said I&M believes the proposed tariff adequately addresses data collection plans and needs. *Id.* at 17.

(h) Tariff Term and Condition 4. Mr. Hix said I&M is willing to accept many of Mr. Dauphnais' suggestions to help clarify the Company's nonresidential deposit policy and make the deposit policy more transparent to customers to better ensure that the policy is applied in a nondiscriminatory manner. He submitted revised language for Term and Condition 4 and discussed areas where the Company did not agree with Mr. Dauphinais' suggested changes. Hix Rebuttal, at 21; Petitioner's Exhibit WWH-R3.

(5) Commission Discussion and Findings. The Commission notes that no party opposed I&M's proposed reorganization of its tariff book or the language in the terms and conditions of the following proposed I&M tariff changes presented by Mr. Hix: the Equal Payment Plan; DNI fee; Reconnection fee; Rider AFS; or I&M's proposed cancellation of Tariff E.H.S. and Riders E.C.S. and E.P.C.S. Similarly, no party opposed I&M's proposed modifications to the language in the terms and conditions of Tariffs O.L., E.C.L.S., M.G.S. and S.G.S. Based upon the evidence of record, the uncontested language changes in the terms and conditions of the above tariffs, riders, rules and regulations are approved as proposed by I&M.

With regard to contested tariff terms and conditions, we address each issue individually, as follows:

(a) Discounted Employee Rate Under Tariff R.S.-TOD2. I&M put forward business arguments for maintaining its long-standing policy of offering employee discounts on electric utility service. Despite tax advantages and a legal framework that does not prohibit the use of such discounts in I&M's employee compensation package, the OUCC expressed concern that employees are receiving unfair price breaks, at other customers' expense. The OUCC also suggested that if utility employees were required to pay the same rates as other utility customers, it might help reduce the amount or frequency of future rate increases.

Although I&M supports the continued use of employee discounts, which it considers a cost-effective compensation tool, given the current economic climate, we find the public interest requires removing employee discounts from I&M's pro forma revenue requirement. Continuing to fund discounts for employees of a monopoly service provider seeking an increase in its authorized utility rates raises concerns of the fairness of the requested rate increase. Therefore, if I&M still considers it beneficial for purposes of recruiting and retaining the best employees, particularly ones residing in I&M's own service territory, I&M should ask its shareholders to fund discounts for its employees, not I&M's captive utility customers.

(b) Optional Senior Citizen Tariff. The proposed modifications to the Optional Senior Citizen Tariff presented in I&M's rebuttal testimony, Petitioner's Exhibit WWH-R1, addressed some, but not all, of the OUCC's concerns. We agree with the OUCC that senior citizens should be fully informed before being permitted to switch from I&M's standard residential service rate to a Senior Citizen Rate they might perceive as a guaranteed price reduction for senior citizens, but which has the potential to trigger the imposition of higher rates and larger monthly electric bills. Although I&M's rebuttal testimony offered some additional protection for senior citizens who find themselves paying more, not less, for service after switching to the new Senior Citizen Rate, the change I&M proposed will not prevent financial harm to seniors whose monthly usage exceeds 1000 kWh. It merely provides an avenue for seniors to avoid continued financial harm if they have to wait a full year before transitioning back to I&M's standard residential service tariff. Since factors outside a customer's control can significantly increase electricity usage from month to month (e.g., extreme weather conditions), it would not serve the public interest to allow Indiana seniors to be subjected to financial penalties when they are attempting to reduce energy usage and prevent waste.

We do, however, recognize the possibility that some Indiana seniors could benefit from an optional service offering. Therefore, rather than reject I&M's proposal outright, we are inclined to invite I&M to submit a proposal designed to allow initial testing of a limited pilot offering, to gather actual data from which to analyze the likely impact of an optional service offering on participating seniors. We invite I&M to submit a pilot proposal, limited to one year in duration and available to a specified maximum number of eligible senior citizens who together constitute a representative cross-section of all eligible customers in I&M's Indiana service territory. We invite I&M to submit a more detailed proposal for such a pilot program in a separate filing. I&M's pilot proposal should include a proposed outline of topics I&M will address in a final report on the results of its pilot program. However, since we share the OUCC's concern that advance disclosures fully and clearly explain potential risks to interested seniors. I&M should include copies of all promotional materials it plans to use in Indiana in a separate filing for review by the OUCC, the Commission, the IURC's Consumer Affairs Division, and other interested parties, allowing them to review all planned promotional materials shortly after they are filed.

(c) Tariff Terms and Conditions 11 and 12. We also share the OUCC's concerns regarding the additional limitation of liability language proposed in by I&M. Although consequential damage to customer equipment is not always the result of negligence or misconduct by an electric utility, this Commission does not have authority to make such determinations. See *Southeastern Indiana Natural Gas Co., Inc. v. Ingram*, 617 N.E.2d 943 (App. 1 Dist 1993). Indiana Courts have jurisdiction beyond that granted to this Commission.

We are reluctant to approve dispositive language that could foreclose relief otherwise available to utility customers under state or federal law. We believe the language I&M proposed reaches beyond traditional utility regulation into an area better left to courts with jurisdiction over civil causes of action. We therefore reject I&M's continued use of certain language in Tariff T&C 11 and reject I&M's pending request to include that language in T&C 12.

(d) Tariff Term and Condition 16. I&M proposed adding language to Term and Condition 16 purporting to reserve to itself the sole authority to make decisions regarding the placement of electric utility infrastructure on private property, whether under a recognized right of way or a private utility easement. Indiana utilities are expected to follow standard engineering and safety standards. However, that does not give the utilities limitless control over property owned by others. The Indiana General Assembly has given utilities the power to file condemnation proceedings when property usage disputes cannot be amicably resolved. (I.C. 8-1-8.) We decline to approve proposed tariff language change that could be read to alter the respective rights of utilities and property owners. We have encouraged Indiana utilities to take property owners' rights into account. (See RM 10-04 and Cause No. 43663.) However, this Commission does not have authority to grant, alter or limit property interests. To the extent the proposed language could be interpreted differently, we decline I&M's request for approval of its proposed change to Tariff Term and Condition 16.

(e) Tariff Terms and Conditions 12 and 17. The OUCC and I&M disagree on the impact of I&M's proposed change to language in T&Cs 12 and 17 regarding involuntary service disconnections without advance notice to affected customers. The Commission has a rule specifically addressing the circumstances under which service disconnections can take place without providing advance notice to customers. The language in Tariff Terms and Conditions 12 and 17 should mirror that previously approved by the Commission in 170 IAC 4-1-16(b). Rather than arguing semantics, we direct I&M to mirror the language in the administrative code in its tariff and include a cite to 170 IAC 4-1-16 in its tariff. In the event a situation requires this Commission to decide a dispute between I&M and a customer whose service is disconnected without advance notice, the Commission will apply its standard rule in determining whether the disconnection was properly made without notice. We also recognize that in rare circumstances it may be necessary for a public utility to take action under 170 IAC 4-1-16 to ensure the continued provision of safe and reliable electric utility service to other customers. That situation is explicitly addressed in 170 IAC 4-1-16(b).

(f) Tariff C.S.-IRP and Tariff C.S.-IRP2. The OUCC requested the removal of certain language pertaining to the filing of special contracts using the Commission's 30-day filing process. The language at issue was the subject of the Commission's February 2, 2011 decision in Cause No. 43878, which involved a dispute over the impact of language in the Commission's recently revised 30-day filing rule in 170 IAC 1-6-4(8) on tariff language that permitted I&M to submit redacted copies of proposed special contracts to the Commission for approval as 30-day filings, with confidential provisions submitted to the Commission under seal, under a standing preliminary finding that pricing information required to support the approval of special contracts be protected from public disclosure as confidential trade secrets, pending a final determination by the Commission. The Order in Cause No. 43878 did require I&M to file supporting affidavit(s) to confirm that information redacted from future submissions of proposed special contracts contain the same type of information the Commission deemed to be entitled to protection from public disclosure in Cause No. 43878. The supporting affidavit(s) would be submitted together with the 30-day filing, without requiring I&M to open a separate docketed proceeding

Under the Commission's ruling in Cause No. 43878, I&M has filed redacted versions of proposed special contracts, after removing confidential pricing information essential to the review and approval of special contracts, despite the express prohibition in the Commission's current 30-day filing rule. 170 IAC 1-6-4(8).

The question to be addressed in this case is whether the Commission should continue to permit I&M to use special expedited proceedings, not available to other providers, to gain approval of special contracts submitted with material redactions using a procedural rule that does not provide sufficient time for other potentially interested parties to obtain and review the redacted information and determine whether to file procedural or substantive objections to such filings. Docketed proceedings conducted pursuant to notice and hearing requirements provide the level of process that is due in contested Commission proceedings, especially those that have the potential to impact end user rates. Special contracts typically involve price reductions for specific customers for a stated period of time. Such agreements can result in a shifting of cost recovery between customers, even if the special discount is being voluntarily funded from surplus profits under I.C. 8-1-2-24.

The Commission's April 27, 2011 Order in an electric rate case filed by Vectren sheds additional light on the need for proper procedural safeguards when reviewing proposed special contracts. In that case, the Commission declined to consider the amount of revenue that Vectren voluntarily gave up during the test year in determining whether Vectren's cost of service study and resulting rate design would produce fair and reasonable rates for other customers. The Commission found that:

> [E]ach special contract, including the proposed rates and charges, has been reviewed and approved by the Commission. This statutory requirement provides assurance that such arrangements are reasonable and just. Ind. Code § 8-1-2-24. The use of special contracts for distinct customers that are not readily served under standard tariff rates makes a subsidy or discount presentation difficult to present and compare in a standard COSS. The limited number of Vectren South special contract customers presents challenges to appropriately controlling proprietary information. ... <u>The Commission finds that consideration of how to most reasonably address any discount or subsidy responsibility should occur in the specific special contract proceedings</u>.

Southern Indiana Gas and Electric Company, Inc. d/b/a Vectren South, Cause No. 41839, Final Order at p. 70 (emphasis added).

In light of the above example of potential situations where the use of special contracts could impact parties' ability to challenge the fairness or reasonableness of rate design in future rate cases, we agree that the expedited 30-day review process does not provide sufficient time for interested parties to obtain access to redacted information and take appropriate action, if desired.

The confidential records exclusion in 170 IAC 1-6-4(8) currently acknowledges that such submissions should not be considered as 30-day filings. We therefore grant the OUCC's request and order I&M to remove the language authorizing confidential submissions to be made in 30-day filings from its proposed Tariff C.S.-IRP and Tariff C.S.-IRP2.

(g) New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage). We note attempts to address many of the OUCC concerns outlined in OUCC Witness Keen's testimony in I&M Witness Hix's rebuttal testimony and Petitioner's Exhibit WWH-R2. We further note the OUCC's recognition of the value of PEV integration into the grid. While I&M's proposed revisions to its tariff appear to be helpful in addressing some of the OUCC's concerns, we share the OUCC's view that PEV integration raises a range of large and small issues which are best addressed by giving interested parties an opportunity to explore the various issues apart from the distractions inherent in litigating a major base rate case. We agree with the OUCC that the most appropriate forum to address the issue is a separate cause before this Commission. While we therefore reject I&M's proposed tariff in this Cause, we encourage I&M to refile it under a separate cause number which will allow a full and proper vetting of this worthwhile issue by all interested parties.

(h) Tariff Term and Condition 4. During cross-examination by counsel for the Industrial Group, Mr. Hix clarified several aspects of Term and Condition 4. First, he acknowledged that the provisions in the rule that reference a cash deposit also apply if instead of cash a surety bond or a letter of credit has been posted. He further clarified that the notice provided to the customer pursuant to paragraph 5 of Petitioner's Exhibit WWH-R3 would be some form of written documentation, either electronic or otherwise. With respect to paragraph 6, Mr. Hix indicated the Company's intent was that if one account of a customer becomes delinquent, the amount of the deposit required would be based on that one account, rather than the total accounts for that customer. Finally, Mr. Hix agreed that the last paragraph in Petitioner's Exhibit WWH-R3 provided two alternative conditions that, if met, would cause I&M to refund a deposit. With the proposed language additions and or changes to proposed Term and Condition 4 described in I&M Witness Hix's rebuttal testimony and Petitioner's Exhibit WWH-R3, and with the clarifications provided during cross-examination, we believe that IG Witness Dauphinais' concerns regarding this tariff have been satisfactorily addressed. Accordingly, we approve the proposed tariff including the revised language recommended in Petitioner's Exhibit WWH-R3.

**15. Off System Sales Margins Sharing Mechanism.**

**A. I&M Case-in-Chief.** Mr. Chodak (Direct, at 17-18) and Mr. Pascarella (Direct, at 4), testified that OSS margins are the revenues I&M is allocated from certain non-firm wholesale sales and other financial transactions made by AEP's Commercial Operations business unit. Mr. Chodak stated that AEP, like all of our investor owned electric utilities, is actively engaged in today's competitive wholesale marketplace and brings considerable resources and expertise to bear in order to manage the attendant risks. I&M Witness William J. Pascarella, AEPSC Director - Generation Load Forecasting, claimed that many off-system sales are no longer linked to physical assets (*i.e.* surplus generating capacity) and are based on financial transactions, whose success is based on a "superior understanding" of wholesale markets and a willingness to actively participate in transactions.

Mr. Krawec noted that I&M proposes to continue OSS margins sharing between customers and the Company through the OSS Margin Sharing Rider. Krawec Direct, at 13-14. However, I&M proposes that the revenue requirement used to establish basic rates for retail service not be "artificially" adjusted downward by OSS margins. *Id.* I&M proposes that all OSS margins be shared *50/50*. *Id.* Under I&M's proposal, the Company will continue to have an incentive to optimize assets and pursue opportunities in the wholesale market for electricity, and I&M customers will continue to receive benefits on a *50/50* sharing basis from the opportunities for OSS margins. *Id.* Mr. Pascarella asserted the Company's proposal results in no downside risk to the customer to the extent that the customer will never receive less than 50% of the total OSS margins, while the Company retains 100% of the downside risk. Pascarella Direct, at 16. He stated that under the Company's proposal, the Company's financial health is protected from the potential material earnings swings that are an inherent risk in the volatile and rapidly changing environment. *Id.* at 17. Mr. Krawec stated that equal and balanced sharing of the OSS margins provides the Company with an incentive mechanism to optimize the margins in a manner that will benefit I&M customers and provide a reasonable reward to the Company as well. Krawec Direct, at 14.

Mr. Chodak and Mr. Pascarella asserted that the current OSS Margin "sharing" mechanism does not effectively balance the attendant risks and rewards between the customer and the Company. Chodak Direct, at 19; Pascarella Direct, at 16. Mr. Chodak claimed that the actual experience under the current framework has resulted in customers receiving over $109 million in benefits and I&M incurring a loss of nearly $120,000. Chodak Direct, at 19. He stated that in today's market and economic conditions, this effectively results in I&M and AEP receiving none of the reward despite having created all of the value.

Mr. Pascarella stated that the competitive wholesale environment for OSS optimization has undergone significant changes since the time of I&M's last rate case. Pascarella Direct, at 9-10. He declared that the economic recession which began in 2008, and the resulting reduction in market energy requirements, the impact of new and pending EPA regulations and the changing commodity relationship between coal and natural gas has created significant challenges for OSS. *Id.* Mr. Krawec said these changed market conditions have caused OSS margins to drop precipitously since I&M's test year used in Cause No. 43306. He claims that the amount of OSS margins for the period March 23, 2009 through June 30, 2011 and the projection through December 31, 2011, shows that the treatment of OSS margins established in Cause No. 43306 has not and will not result in the fair sharing of OSS margins or result in a reasonable balancing of the interests of both the customers and the Company. Krawec Direct, at 12.

Mr. Pascarella stated that observing the dramatic changes in the underlying components that drive electricity prices, such as natural gas, coal, and emissions allowances, is one of the easiest ways to see how much things have changed in the wholesale electricity markets in the last 4 years. Pascarella Direct, at 10. He identified and described changes in the underlying components using the traditional measure of volatility, referring to the unpredictable price changes over time, and typically measured using the standard deviation. *Id.* He also described the dramatic "step changes" that have occurred since the last rate case. [Tr. at H-123]. He identified the economic downturn which began in 2008 and its resulting impact on load growth and the demand for energy as one of the most significant step changes that has occurred. [Tr. at H-123]. He asserted that, as the recent economic downturn has shown, there are many factors that are beyond the control of the utility even though AEPSC actively manages the risks associated with the wholesale power market. Pascarella Direct, at 10.

Mr. Pascarella testified that natural gas-fired generation has played an impactful role on the wholesale price of electricity in PJM and other RTOs. Pascarella Direct, at 10. He stated that whether the gas price trend is just reflecting the recent economic slowdowns, or the recent discoveries and development of economic extraction methods from shale fields such as Marcellus, there has been downward pressure on the price. *Id.* at 10-11. He added that new environmental regulations on NOx and $SO_2$ set to take effect as early as January 1, 2012 may drive natural gas demand to new highs. For now, the data clearly shows declining volatility for natural gas. *Id.* at 11. Mr. Pascarella asserted coal prices have also shown a high degree of volatility and uncertainty. coal prices have ranged from a low of approximately $39/ton to a high of approximately $143/ton. *Id.* at 11. He stated the PJM switching from coal fired units to natural gas fired units may put downward pressure on coal costs. However, mining techniques in the East are under environmental pressures preventing the use of more economic extraction methods. Also, as coal burners look to burn coal with less sulfur, lower sulfur Powder River Basin ("PRB") coal will be in higher demand creating upward price pressures for this product. Id. Mr. Pascarella explained that the OSS opportunities are also affected by changes in environmental regulation. *Id.* at 11-13.

Mr. Chodak and Mr. Pascarella attempted to differentiate I&M's OSS optimization activities with those of other Indiana utilities. As argued by Mr. Chodak, AEP could theoretically separate the traditional and non-traditional wholesale market activities conducted by its Commercial Operations group, as other utilities have done, into a stand-alone business and manage that activity for the sole benefit of its shareholders. Chodak Direct, at 17. Mr. Chodak explained that AEP has not chosen this path but is instead proposing an OSS margin sharing mechanism in this case that would continue to share the revenues produced by its wholesale business with its retail customers. *Id.* at 17-18.

Mr. Pascarella explained that the Commercial Operations business unit is currently part of AEPSC and performs OSS optimization activities on behalf of I&M and other AEP companies. That structure was established based on the symbiotic relationship between the functions necessary to serve native load customers and the non-traditional opportunities available in the wholesale markets. Pascarella Direct, at 3-4. He stated I&M's unique approach to OSS optimization results in outsized margins because the sum of the various traditional and non-traditional trading activities results in a sum that is greater than its individual parts. At the February hearing, Mr. Pascarella testified that the synergistic Commercial Operations business model provides additional wholesale benefits to retail customers; whereas, other Indiana utilities are focused just on serving retail load, and some literally have a separate entity that is deregulated to generate the wholesale margins. [Tr. at H-126].

As discussed by Mr. Pascarella, OSS margins are derived from traditional and non-traditional activities and include both physical and financial trading. The physical sale of surplus energy is just one way that OSS margins are made. The non-traditional activities include the company's participation in competitive energy auctions outside of AEP's service territory in PJM and in the Midwest ISO, the use of financial energy trading instruments and active hedging. Pascarella Direct, at 5. Mr. Pascarella testified that many of the mega-watt hours involved in

AEPSC's trading transactions are never physically delivered, but are simply trades either buying or selling, in the wholesale electric market. *Id.* at 6. He stated that these may include physical transactions that are "booked out", as well as purely financial transactions that do not contemplate physical flow. *Id.* A "booked out" transaction occurs when AEPSC has a purchase and a sale of the same quantity for the same specific delivery period at the same specific delivery point. *Id.* The offsetting sale and purchase transactions are financially settled rather than physically delivered resulting in "booked out" transactions. *Id.* Mr. Pascarella explained that over the past few years, AEP's physical generation allocated to OSS is typically only 35% to 40% of the total volume of OSS for any given year. The remaining 60% to 65% of sales volume is derived from "non-traditional" sales. *Id.* at 6-7.

Mr. Pascarella stated AEP applies the risk management techniques it has honed through its trading and risk management activities to its traditional utility operations in PJM in many ways. These techniques are designed to allow AEP to maximize OSS margins. Pascarella Direct, at 8. He testified that OSS margins from PJM markets are not simply the result of bidding all surplus energy that can be sold on an hourly or day-ahead basis into the market. Rather, to maximize margins in this short-term (i.e., hourly or day-ahead) market, AEPSC utilizes its Commercial Operations group to leverage "traditional" utility experience, such as engineers with power plant experience, as well as operations research, financial performance analysts, energy marketing and trading teams, energy market analysts, meteorologists to forecast weather impacts, economist to forecast load/demand and transmission specialists that can understand physical transmission limitations and congestion. *Id.* at 14.

Mr. Pascaralla also testified that other examples of risk affecting operations in the wholesale market place include: credit risk; counterparty performance risk; volumetric risk; and basic risk. *Id.* at 13-14. He also discussed some of the ways that AEPSC manages assets within the complexities of the PJM market. *Id.* at 14. He also explained how current conditions and EPA regulations have increased the risk inherent in operating a generation fleet and serving load in this new marketplace. *Id.* at 15-16.

Mr. Krawec explained that per the Commission's Order in Cause No. 43306, I&M's current rates and charges for retail electric service reflect OSS margins in both basic rates and through a rate adjustment mechanism. More specifically, the revenue requirement used to establish I&M current basic rates for retail service includes a credit of $37.5 million of OSS margins allocated to the Indiana retail jurisdiction. In other words, I&M's cost of providing retail electric service in Indiana was reduced by $37.5 million of anticipated margins from AEP's wholesale market operations. Krawec Direct, at 11-12; Chodak Direct, at 19. He stated that in Cause No. 43306, the OSS Margin Sharing Rider was also approved. He explained that the OSS Margin Sharing Rider tracks OSS margins above the $37.5 million reflected in basic rates and shares any such margins 50% to customers and 50% to the Company. The OSS Margin Sharing Rider factors are established annually based upon a projected level of I&M OSS margins and includes a reconciliation of actual OSS margins realized and actual rider revenues for a reconciliation period. Importantly, as currently designed, there is no adjustment to basic rates or to the rider, if actual jurisdictional OSS margins fall below the $37.5 million annual threshold. This means that I&M's current basic rates were established using a revenue requirement that depends on the wholesale market to cover $37.5 million of the cost I&M incurs to provide retail electric service. *Id.* at 12.

Mr. Krawec argued that the treatment of OSS margins in Cause No. 43306 did not fairly balance the interests of customers and the Company. *Id.* at 12. Mr. Krawec presented a Table that showed the sharing of OSS margins for the period March 23, 2009 through December 31, 2011 under the sharing mechanism established in Cause No. 43306. Mr. Krawec argued that this data showed that the imputation of wholesale revenues established in Cause No. 43306 did not provide a fair sharing. During the February hearing, Mr. Krawec stated that over the identified period I&M's jurisdictional OSS margins were $109,128,889. *Id.* at 13. Customers received the benefit of $109,248,407. *Id.* Mr. Krawec stated on cross examination that the Company has generated approximately $120,000 less in off-system sales than what I&M has credited to the customer. [Tr. at N-43]. Mr. Krawec stated that I&M proposes to change the treatment of wholesale market margins in this case because the current treatment is not fair. Krawec Direct, at 13. Mr. Pascarella added that the volatility of wholesale markets for electricity have changed dramatically over the past years. Pascarella Direct, at 17. He said increased uncertainty in the economy's effects on energy demand, new and pending environmental regulations, and volatility in underlying commodities are the key factors that have led to a markedly changed OSS environment. *Id.* He further testified that the OSS margin levels that were being attained at the time of I&M's last Indiana base rate case have not been attained since and are forecasted to remain significantly less than the amount ($37.5 million) currently embedded in I&M's base rates. *Id.*

Mr. Krawec clarified that the factors reflected in the OSS Margin Rider would continue to be established annually based upon a projected level of I&M OSS margins and would include a reconciliation of actual OSS margins and corresponding rider credits applied to customer bills during the reconciliation period. *Id.* at 14. He suggested that as new basic rates and charges would be implemented following a Commission order in this Cause, I&M could revise its OSS Sharing Margin Rider. He said the modification would reflect the *50/50* sharing of all of the jurisdictional OSS margins forecasted in the most recent OSS Margin Sharing Rider proceeding approved by the Commission prior to the filing of the revised Rider. *Id.* Thereafter, in the OSS Margin Sharing Rider Reconciliation, the reconciliation would be prorated to reflect the methodology established in Cause No. 43306 and the new methodology, with any over/under recovery of OSS Margin Sharing Rider amounts being included as an adjustment to the new factors in that reconciliation proceeding. *Id.* at 14-15. Mr. Krawec added that I&M proposes to make a compliance filing reflecting an adjustment that would result in a $14 million credit to customers under the proposed OSS rider, based upon the recently filed forecast in Cause No. 43775 OSS-2, dated August 26, 2011. *Id.* at 15.

**B. <u>OUCC Case-in-Chief.</u>** OUCC Witness Wes R. Blakley described Petitioner's current treatment of OSS margins as a result of the Commission's Order in Petitioner's last rate case, Cause No. 43306. He explained that per the Commission's Order in that case, a credit of $37.5 million of OSS margins was allocated to the Indiana Jurisdiction and is currently reflected in I&M's basic rates. That Order also approved the OSS Margin Sharing Rider in which OSS margins above the $37.5 million reflected in basic rates are tracked and shared equally between customers and shareholders.

Mr. Blakley disagreed with Petitioner's proposal in this case to remove the $37.5 million OSS margin credit currently reflected in basic rates so that *all* OSS margins are tracked and shared 50% to customers and 50% to shareholders from the first dollar. He did not agree that there is a need to change the design of Petitioner's OSS Margin Sharing Rider by eliminating the credit for OSS margins in base rates, as proposed by Petitioner. Mr. Blakley recommended, consistent with the Commission's Order in I&M's last rate case in Cause No. 43306 and consistent with other Indiana electric utilities that have an OSS margin sharing mechanism, a credit amount for OSS margins be embedded in I&M's base rates. He explained that changes in rules and regulations, the economy, consumption or demand and technological advancements are always possible and may or may not affect wholesale electricity markets. Blakley at 11. He presented historical and projected data in support of his position that I&M still consistently receives a significant amount of OSS margins. Mr. Blakley explained that the data provided by I&M does not support I&M's assertion that forecasted OSS margins are significantly less than the $37.5 million currently embedded in I&M's basic rates. *Id.*

Mr. Blakley recommended that a credit of $32,908,567 be built into Petitioner's base rates for Indiana jurisdictional customers ($50,477,473 for I&M Total Company). His recommended OSS margin base rate credit was based, not on the test year amount of $37.5 million, but on I&M's smallest Indiana Jurisdictional OSS margins amount achieved over the past five years (2007 through 2011). He provide a chart of I&M's test year OSS margins, pro forma OSS margins, and five-year historical average OSS margins, which by comparison suggested that a base credit of approximately $32.9 million should be considered an achievable base level. Consistent with Petitioner's current OSS margin sharing mechanism, Mr. Blakley recommended a 50/50 sharing of OSS margins *above* his recommended base rate amount. *Id.* at 12-13. Mr. Blakley stated that the 50/50 split *above* the base rate amount continues to provide an incentive for I&M to operate its power plants efficiently and maximize investments, yet does not provide an unfair sharing arrangement for the ratepayers, who are assuming operation and maintenance expenses and supporting the rate base through retail rates.

Based on Mr. Blakley's recommendation, OUCC Witness Eckert increased operating revenues by $50,477,473 on a total company basis. Of this total increase, $32,908,567 is allocable to the Indiana jurisdiction. Eckert at 17. OUCC Witness Nicholson testified that if the Commission accepts Mr. Blakley's recommendation, it should direct I&M to allocate the benefits of the OSS margins within the cost of service study the same way that it allocates the costs of production plants in the study. Nicholson at 33.

**C. <u>IG Case-in-Chief.</u>** IG Witness Dauphinais recommended the Commission require I&M to retain $37.5 million in annual OSS margins in its base rates and continue sharing OSS margins above $37.5 million with customers on a 50/50 basis through its OSS Rider. Mr. Dauphinais' recommendation would reduce I&M's base rate revenue requirement by $37.5 million. Dauphinais at 2, 7. Mr. Dauphinais acknowledged that I&M's Indiana-jurisdictional OSS margins have fallen from an annual level of approximately $96.0 million in Cause No. 43306 to an average annual level of $40.6 million for the period of July 1, 2009 through June 30, 2011. He noted I&M is also forecasting Indiana-jurisdictional annual OSS margins will continue to fall from January 1, 2012 through December 31, 2012. *Id.* at 5. Mr. Dauphinais testified that these lower levels of OSS margins do not, however, justify dropping the OSS margins included in base rates to zero. He stated that the fall in OSS margins from approximately $96.0 million annually to an average level of $40.6 million has not resulted in I&M Indiana ratepayers being allocated OSS margins through I&M's base rates and OSS Rider that are in excess of I&M's actual Indiana-jurisdictional OSS margins. *Id.* at 6. He also asserted that while I&M may be forecasting lower annual OSS margins for calendar year 2012 in its Cause No. 43775 OSS-2 filing, reasonable ratemaking adjustments to test year values are not based on forecasted amounts because a forecasted value is not a known and measurable value. *Id.* Mr. Dauphinais suggested that if the Commission concludes that some risk sharing of OSS margins between I&M and I&M customers should occur below $37.5 million of OSS margins, $37.5 million in OSS margins should be retained in I&M's base rates, but the OSS Rider should be modified to share OSS margin shortfalls of up to $37.5 million from this amount between I&M and I&M's retail customers on a 50/50 basis. *Id.* at 7.In Cross-Answering Testimony, IG Witness Phillips testified that I&M's allocation of off-system sales margin is reasonable. Phillips Cross-Answering at 2.

**D.** **SDI Case-in-Chief.** In his prefiled Direct Testimony, SDI Witness Smith recommended that I&M's OSS Margin Sharing Rider provide that Indiana retail customers' share of jurisdictional OSS margins be 75% of the Company's Indiana jurisdictional OSS margins. He testified that this is the ratio I&M agreed to in a settlement in Michigan that was approved by the Michigan Public Service Commission and therefore it would be equitable to apply the same ratio to I&M's Indiana customers. Smith Direct, at 38-39. However, in his Cross-Answering Testimony, Mr. Smith adopted the OUCC's recommendations regarding OSS margin sharing. Smith Cross-Answering at 13.

**E.** **South Bend Case-in-Chief.** South Bend Witness Reed W. Cearley, utility consultant, recommended that the Commission reject I&M's proposed treatment of OSS margins. He recommended the Commission should continue with its practice of reflecting 100% of test year OSS margins in base rates, which would reduce I&M's proposed revenue requirements by approximately $18.75 million. Cearley at 4. Mr. Cearley testified that with respect to OSS margins, 100% of the initial margins should accrue to ratepayers because they are the ones who pay for the assets that provide the OSS margins. He stated that I&M has not established that it needs to increase its share in OSS margin benefits and that I&M's evidence shows that the annual threshold of $37.5 million is "about right." *Id.* at 4-5.

**F.** **I&M Rebuttal.** I&M Witness Chodak argued that acceptance of the OUCC's and Intervenors' recommendations would not only be unfair, but would potentially harm I&M's ability to serve its customers and guarantee that I&M would not have a reasonable opportunity to earn the return authorized by the Commission in this case. He explained that over the last three and one-half years, the existing mechanism resulted in I&M taking a significant loss and customers receiving credit for more than 100% of the OSS margins actually earned. Chodak Rebuttal, at 10. He characterized the OUCC's and Intervenors' recommendations as asymmetrical and stated that such treatment fails to recognize the value created by I&M's OSS agent, AEP Commercial Operations, and the fact that much of the OSS margins result from trading activities and not simply the sale of excess generation. *Id.* at 10-11. Mr. Chodak also testified that the OUCC's recommended approach would treat I&M differently from other utilities that are able to share up or down from the level embedded in the revenue requirement used to establish basic rates. He provided a simple example to demonstrate the one-sidedness of the proposed asymmetrical sharing. He explained that under the OUCC's recommendation that a revenue credit of nearly $33 million (Indiana jurisdictional) be included in basic rates with sharing applicable only to the incremental amounts in excess of that, if actual OSS margins were $25 million, I&M would lose $8 million, while customers would receive 132% of the actual amount of OSS margins. He went on to show that even if actual OSS margins were $40 million and thus exceed the $33 million the OUCC would lock into basic rates, I&M's share would be 8.75%, while the customers' share would be 91.25%. Mr. Chodak provided evidence that actual OSS margins would have to reach nearly $200 million annually before the sharing would come close to even a 60/40 sharing ratio where I&M retains 40% of its OSS margins. *Id.* at 11-12. He explained that Mr. Dauphinais' alternative recommendation concedes that sharing should reflect amounts above and below the amount embedded in basic rates, but his proposed sharing starts from an even higher amount than recommended by the OUCC. Mr. Chodak explained that even then, there remains an imbalance between the efforts made to create value and the level of reward to the value creator. He explained that the 50/50 sharing of incremental changes in OSS margins, even when it is applied above and below the amount embedded in basic rates, does not actually result in a 50/50 sharing arrangement. *Id.* at 12-13.

In rebuttal, I&M Witness Krawec argued that the OUCC and IG's proposals regarding OSS margin sharing do not fairly recognize the impact of the earnings test imposed in the FAC proceedings. He explained that the Settlement Agreement approved in Cause No. 43306 provided that I&M's share of OSS margins and net positive financial transmission rights ("FTR") revenues under the OSS margins sharing mechanism are excluded from the earnings test in determining I&M's compliance with the provisions of IC 8-1-2-42(d)(3) and IC 8-1-2-42.3. He stated this approach recognizes that I&M should not lose its "share" of OSS margins through the application of the earnings test in the FAC proceedings and thus gives effect to the sharing and balancing of risk and reward. Cause No. 43306 Order, at 24, 25. He noted that the testimony in support of the settlement agreement approved in Cause No. 43306 indicated that the provision regarding the earnings test is reasonable because the OSS margin sharing mechanism agreed to there differs from the sharing mechanism used by other Indiana utilities in that it applies only to margins above the amount embedded in the revenue requirement. Krawec Rebuttal, at 45. He testified that the one-way sharing proposals offered by the OUCC and IG are unreasonable because these proposals, if adopted, would have the effect of clawing back I&M's "share" of the OSS margins via the operation of the earnings test absent the extension of the above-referenced exclusion established in Cause No. 43306. *Id.* at 46.

I&M Witness Kevin T. Brady, testified that the OSS margin sharing proposals offered by these other parties would effectively eliminate any meaningful opportunity for the Company to share in the OSS margins it creates and that the OUCC's and Intervenors' OSS margin sharing proposals fail to account for the differences between I&M's OSS margins and those of the other Indiana utilities. Brady (Adopted Busby) Rebuttal, at 2-3. Mr. Brady criticized OUCC Witness Blakley's reliance on the past five years of historic performance, stating that the wholesale market has changed dramatically over that time and past results are not an indicator of future performance. He explained that the wholesale market in general is volatile and shale gas, environmental regulations, and a dismal economy have greatly affected I&M's expectation for OSS margins. He testified that the OUCC's recommendation is inconsistent with even the existing sharing mechanism because, if the OUCC truly believes I&M's going forward OSS margins will be $32.9 million, it is in essence seeking 100% of that amount by locking it into basic rates. *Id.* at 3. Similarly, Mr. Brady stated, the IG's recommendation seems to be an attempt to capture at least 100% of the OSS margins and an abandonment of the sharing concept developed in the last case and recognized as reasonable and appropriate by the Commission in past cases. *Id.* He noted the IG's position also fails to recognize the Commission's findings on this issue in cases where the OSS margins sharing issue was litigated (Cause No. 42359 and Cause No. 43839) in which the Commission approved sharing above and below the amount embedded in basic rates.

Mr. Brady testified that the expectation was that under the existing mechanism the Company would maintain meaningful retention of a portion of the OSS margins. He stated the dramatic disconnect between expectations and results reveals the shortcomings in the existing mechanism. He asserted that the OUCC's proposed sharing mechanism is ineffective in dealing with the volatile and unpredictable nature of I&M's OSS margins, leaving the actual allocation between customers and the Company at the mercy of market fluctuations outside the Company's control. *Id.* at 6-7. In contrast, Mr. Brady opined, the Company's proposed *50/50* from dollar one mechanism presents a resolution that is fair to both the customers and the Company. *Id.* at 6.

Mr. Brady also testified that the source of I&M's OSS margins distinguishes it from other Indiana utilities' OSS sales. He explained that I&M's OSS activity encompasses a much broader scope than simply the sale of excess physical generation. He described the OSS margin activities carried out by AEP's Commercial Operations on I&M's behalf as including such things as auction participation, basis trading, time-spread and spark spread trading in addition to the physical sales of surplus energy and associated hedging. He stated that a portion of that activity could be described as asset optimization, but that is only one of many OSS activities conducted by Commercial Operations as part of its OSS margin maximization activities. *Id.* at 10. He testified that when the OSS margin results of I&M are compared with NIPSCO, PSI, and Vectren, significant differences are readily apparent which have not been taken into account by the OUCC and IG. *Id.* at 11. He showed that trading margins are one of the additional margin streams that AEP executes in the wholesale market. *Id.* at 13-14. He presented evidence that trading margins have created over 44% of the total OSS margins, yet I&M was not able to share in even 1% of the benefits due to the high embedded level of OSS margins in rates. *Id.* at 15-16.

Mr. Brady argued that the OUCC's proposal would in fact penalize I&M for its past success in utilizing trading activities to optimize OSS margins. He showed that when the trading activities are removed, I&M's 2009 OSS margin level (which the OUCC suggested using to set the base rate credit) drops to $11.2 million and setting the credit at $32.9 million effectively inflates the size of the credit going forward because I&M successfully produced significant OSS margins through trading activities. *Id.* at 16. Mr. Brady testified that if the Commission determines that the lowest level of margins over the last five years should be embedded as a credit in rates, the amount of that credit should be $11.2 million, not the $32.9 million proposed by the OUCC. *Id.* at 17.

**G. <u>Commission Discussion and Findings.</u>** We disagree with I&M's argument that the current OSS margin sharing mechanism is flawed and has not functioned as originally designed. The OSS margin sharing mechanism was created in Cause No. 43306 for customers and I&M to share in the risks and rewards of AEPSC efforts to maximize OSS margins in today's wholesale markets. Although historical data shows a downward trend in OSS margins, the OSS margin sharing mechanism has functioned as intended. Consistent with the goals we identified for OSS margin sharing mechanisms in our Order in Cause No. 43839, we find I&M's current OSS margin sharing mechanism design benefits customers and Petitioner and provides Petitioner with an incentive to maximize OSS margins.

All parties agree that a mechanism to share OSS margins is appropriate for I&M. However, the parties disagree on the appropriate level of OSS margins, if any, to include as a base rate credit, and the sharing mechanism to account for actual off-system sales over or under the base amount included in rates.

I&M's generation fleet supports its service to retail customers and also, when available, can be dispatched by PJM to meet wholesale needs in the energy market. As indicated by I&M, the ability to sell at wholesale is a function of a number of factors that include uncertainty in the economy's effects on energy demand, new and pending environmental regulations, and volatility in underlying commodities that drive electricity. The OUCC explained that changes in rules and regulations, the economy, consumption or demand and technological advancements are always possible and may or may not affect wholesale electricity markets. Currently, I&M provides an off-system margin credit to its base rates of $37.5 million, and the Company and customers share in increases around that amount on a *50/50* basis.

All witnesses acknowledged that I&M's Indiana-jurisdictional OSS margins have fallen from an annual level of approximately $96.0 million in Cause No. 43306, however the OUCC and Intervenors testified that these lower levels of OSS margins do not justify dropping the OSS margins included in base rates to zero. From 2007 through 2011, I&M achieved OSS margins in excess of $37.5 million per year, with the exception of 2009, in which OSS were $32.9 million. I&M's OSS margin for the test year ended March 31, 2011 was $43.5 million. The pro forma period ending on March 31, 2012, only declined to $36.7 million. I&M's projected annual results for 2012 and 2013 fluctuated up and down from this pro forma period amount.

As with our review of OSS margin sharing mechanisms in previous rate cases, we rely upon an historic test year, and in certain circumstances we can and do look at forward projections to determine a reasonable level of expense or revenue. Parties agree the nation has been in the midst of an economic downturn, which has led to reduced demand for energy. However, most credible forecasts project at least moderately increased demand in the near future. Based upon the evidence, it is not prudent to set the WPM margin at the test year amount of $43.5 million. Neither however, is it reasonable to exclude an OSS margin credit amount from base rates.

Historical and projected data shows OSS margins remain significant and we agree with the OUCC and Intervenors that it is appropriate to include an amount of OSS margins as a credit against base rates. In essence, this amount will serve as an offset to the Revenue Requirement otherwise determined in this case. This is consistent with our rulings in the most recent electric base rate cases, Cause Nos. 42359, 43111, 43306, 43526, 43839, and 43969.

With respect to determining an appropriate amount to include as an offset, we are mindful of Petitioner's concerns that OSS margins are substantial and highly volatile, and therefore we agree with the OUCC that the OSS margin base rate amount should be adjusted to an amount, that based on historical and projected data, is more sustainable by I&M. The OUCC recommended that the smallest annual margin amount achieved by I&M during the past five years be used.

We agree with the OUCC's recommendation and find that I&M shall credit base rates by $32,908,567. We authorize I&M to track OSS margins above the base rate credit amount with 50% credited to consumers and 50% to I&M. This percentage of margin sharing is more consistent with

I&M's current OSS margin sharing mechanism and other electric IOU's that track OSS. We also find that in tracking such margins, I&M may not apply a net annual margin of less than zero to the tracker, and all OSS net income shall be included as jurisdictional income for purposes of the FAC earnings test.

Like other revenues and expenses, the OSS margin credit should be set at a level that reasonably represents likely results in the future. I&M's base rates currently include an OSS margin credit of $37.5 million. In light of the evidence of the recent reduction in I&M's achieved OSS, we find a reduction in the OSS credit to $32.9 million is reasonable.

In light of the uncertainty surrounding future wholesale performance, we find continuation of sharing any increases in annual performance on a *50/50* basis between the Company and its customers. However, while recognizing this high level of market uncertainty, both the OUCC and the Industrial Group recommended that the Company bear all risks with respect to failure to achieve the base level amount. Petitioner claims this would change the revenue tracking mechanism from a symmetrical sharing of performance risk and reward, to an asymmetrical mechanism where customers have a guaranteed credit and benefit from increased wholesale revenues without any downside risk. However, we find that symmetry is not a requirement in setting rates. It is not imperative for revenues to equal expenses.

The existing mechanism benefits both customers and the Petitioner and provides an incentive for I&M to sell into the market to at least meet, if not exceed, the base credit amount and thereby avoid a shortfall. The parties acknowledge the decrease in I&M's revenues and the reduced demand for energy. However, this does not entitle I&M to make changes to the design of the existing OSS margin sharing mechanism. Therefore, we find I&M shall continue to share excess revenues with customers on a *50/50* basis.

I&M derives a substantial percentage of its OSS margins from non-traditional activities. We begin by noting that we have not previously addressed the distinction between traditional and non-traditional OSS sources in our previous orders. As explained by I&M's witnesses, traditional OSS margins result from the sale of excess power into the wholesale market. If I&M and its sister companies are meeting available customer demand at less than full capacity, they can use their physical assets to generate and sell excess power into the OSS market. Profits from these sales contribute towards I&M's OSS margins. In our previous orders addressing OSS margins, we have focused exclusively on OSS margins as a whole and have not distinguished traditional OSS margins from non-traditional OSS margins. *Re PSI*, Cause No. 42359 (IURC 5/18/2004), at116; *Re Vectren*, Cause No. 43839 (IURC 4/27/2011), at 40; *Re NIPSCO*, Cause No. 43526 (IURC 8/26/2010), at 36.

I&M has presented evidence that it generates a substantial percentage of its OSS margins through non-traditional means that are unconnected to generating asset optimization or the sale of excess power. Similar to non-traditional transactions of other Indiana Electric IOU's who share with customers the profits of such transactions, these non-traditional methods include participation in auctions, "booked out" transactions, basis trading, time-spread trading, spark spread trading, and hedging. If the Company is able to sell the power for more money than it paid to purchase it, the Company makes a profit. If not, it suffers a loss. We find both I&M's traditional and non-traditional profits and losses to be a part of its OSS margins. This is consistent with the treatment of all other Indiana Electric IOU OSS margins. Although these non-traditional OSS margins are not the direct result of utilizing physical generating assets, these financial transactions would not be possible without the use of other I&M's assets. These *other* I&M assets are supported by customers in the form of a return on and a return of these assets. Additionally, customers are paying the salaries and benefits of I&M's Commercial Operations personnel who complete these transactions.

Given the substantial magnitude of I&M OSS margins, their high volatility and the high proportion of OSS margins that I&M generates through traditional and non-traditional methods and given our continuing belief that proper balancing of I&M's and the ratepayers' interests "will provide a benefit that may not otherwise be possible," we agree with the OUCC that the most reasonable and fair method for allocating OSS margins is to allow I&M and the ratepayers to share equally (50/50) in all OSS margins above the base rate amount of $32.9 million. This recognizes the inherently volatile nature of the OSS market and the many variables that are outside of I&M's control; it guarantees a pre-defined and equitable level of sharing between the parties; and yet it allows the customers to share in the profits generated through I&M's traditional and non-traditional activities. We hereby adopt the OUCC's proposal with respect to OSS margins.

### 16. Transmission Service.

**A. I&M Case-in-Chief.** I&M proposes that the following transmission-related cost components related to I&M's obligations as a PJM Load Serving Entity ("LSE") be included in basic rates for transmission service: Network Integration Transmission Service ("NITS"), pursuant to PJM Open Access Transmission Tariff ("OATT") Attachments H-14 and H-20; Firm and Non-Firm Point-to-Point ("PTP") Revenues, pursuant to PJM OATT Attachment H-14; Transmission Owner Scheduling, System Control and Dispatch Service, pursuant to PJM OATT Schedule 1A; PJM Expansion Cost Recovery Charges ("ECRC"), pursuant to PJM OATT Schedule 13; and AEP RTO Start-up Cost Recovery Charges, pursuant to PJM OATT Attachment H-14. Roush Direct, at 20-21. Mr. Roush discussed each of the foregoing charges. *Id.* at 21-23. He explained that the Company's transmission costs should be based upon the charges under the PJM OATT for a number of reasons, including: (1) I&M no longer has exclusive control over its transmission costs because of its membership in PJM; (2) comparability in transmission charges with other Indiana customers in the AEP Zone, who pay the FERC approved OATT charges; (3) proper separation of I&M's costs to provide retail electric service as a LSE from I&M's costs and wholesale revenues as a Transmission Owner ("TO"); and (4) I&M is charged for transmission service regardless of facility ownership. *Id.* at 23-24. He explained that under the Company's proposal, the rates Indiana customers pay for retail electric service will better reflect the transmission service costs that I&M incurs as their LSE. *Id.* at 24. He said the Company's entire traditional embedded cost of transmission, net of the revenues the Company receives from PJM as a TO, have been removed from the Company's revenue requirement in this proceeding, as shown in Petitioner's Exhibit A-1. He added that, as proposed by I&M, the basic rates for retail electric service will no longer directly reflect the cost of I&M's transmission investment, I&M's transmission operation and maintenance expense and all other I&M-specific transmission-related costs. *Id.*

**B. OUCC Case-in-Chief.** Mr. Eckert recommended that the

Commission maintain the current and traditional method of embedding revenue requirements associated with the use of I&M's transmission system for the provision of Indiana retail service. Eckert at 42-44. Mr. Eckert testified that he was not aware of any electric utility in Indiana that follows the practice proposed by I&M, and this proposal would result in a fundamental shift in Indiana ratemaking practices. *Id.* at 42. Mr. Eckert testified that I&M did not provide any information to show that the current mechanism is harming its ability to provide customers electric service and did not put forth any persuasive arguments why a major revenue requirement, like transmission revenues and expenses, should be omitted from base rates. *Id.* at 43. He stated that transmission is one of the three major functions that a vertically integrated electric utility provides and it represents a large revenue requirement. *Id.* Mr. Eckert concluded that I&M's proposal to exclude transmission revenues and expenses from base rates is not an improvement to electric utility ratemaking. *Id.*

**C. <u>IG Case-in-Chief.</u>** IG Witness Dauphinais raised a concern that I&M's proposal could be viewed as a request for the Commission to cede its ratemaking authority over the transmission component of I&M's Indiana-jurisdictional retail revenue requirement to FERC. Dauphinais Direct, at 12. After explaining this concern, Mr. Dauphinais concluded that it appears I&M's proposal in this proceeding helps rather than harms I&M's Indiana retail customers. *Id.* at 14-15. Mr. Dauphinais recommended if the Commission accepts I&M's proposal, the Commission should make it clear that it is only accepting I&M's proposal in the context of the specific facts presented in this proceeding and that in no way is the Commission ceding its ratemaking authority over the transmission component of I&M's bundled retail electric rates in Indiana by accepting I&M's proposal in this proceeding. *Id.* at 16.

**D. <u>I&M Rebuttal.</u>** Mr. Roush clarified that in this proceeding the Company is not proposing to track its transmission costs in the PJM Cost Rider as suggested in Mr. Eckert's description of I&M's proposal. Roush Rebuttal, at 14. He explained that I&M proposes to include in its basic rates for transmission service the specified transmission-related cost components related to I&M's obligation as a LSE. However, Mr. Roush proposed that OUCC Witness Eckert's interpretation of I&M's proposal is a good idea. He stated that if I&M were to track transmission costs in the PJM Cost Rider, it would ensure that customers pay rates that reflect no more or less than the actual cost of transmission service. Roush Rebuttal, at 14-15. Mr. Roush suggested that the Company's proposal regarding the OATT adjustment is appropriate ratemaking. He alleged that the Company supported the calculation of and rationale for the adjustment in its pre-filed direct testimony, exhibits and workpapers. *Id.* at 15. He said that should the Commission approve the Company's proposal, the amount of the adjustment will change as a result of any other changes to the Company's case as filed, since the values are directly calculated from the class cost-of-service study. *Id.* at 16. He speculated that if the Commission rejects the Company's proposed adjustment, the revenues and expenses under the FERC-approved Transmission Agreement would remain in the cost-of-service as well as I&M's own transmission investment and costs and thus the Company's adjustment would be $0. *Id.*

**E. <u>Commission Discussion and Findings.</u>** We find no compelling evidence was presented in this cause by Petitioner or any of the other intervening parties to warrant the Commission making a fundamental shift in Indiana ratemaking practices. While transmission service is provided under FERC-approved OATT rates, it nevertheless remains a basic part of what public utilities must do to provide retail electric service and an essential component of Petitioner's state jurisdictional obligation to provide adequate service. Nothing has been presented by way of evidence that shows us that changes are needed, or why we should take an approach which has not yet been sought by any other Indiana utility. We decline to take steps which might be interpreted to dilute this Commission's jurisdiction as to transmission issues, and we deny Petitioner's proposal to include the FERC-approved OATT charges in basic rates.

**17. Timing of Next Rate Case.**

[OUCC did not file testimony or take a position on this issue and defers to the parties participating on this issue to state their respective positions and argue the merits.]

**18. Confidentiality.** Petitioner made two motions for protective order, all of which were supported by affidavit or testimony showing documents to be submitted to the Commission were trade secret information within the scope of I.C. §§5-14-3-4(a)(4) and (9) and I.C. § 24-2-3-2. In addition, SDI filed an Unopposed Motion for Preliminary Protection of Claimed Confidential and Proprietary Information for which Petitioner provided a supporting Affidavit. The Presiding Officers issued a Docket Entry on October 4, 2011, May 23, 2012 and May 29, 2012, respectively, finding such information to be preliminary confidential after which such information was submitted under seal. We find all such information is confidential pursuant to I.C. § 5-14-3-4 and I.C. § 24-2-3-2, and is exempt from public access and disclosure by the Commission.

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

1. Petitioner shall be and hereby is authorized to adjust and increase its rates and charges for electric utility service to produce an increase in total operating revenues of approximately 2.30% in accordance with the findings herein which rates and charges shall be designed to produce total annual operating revenues of $1,338,292,726, which are expected to produce annual net operating income of $148,163,509.

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

3. Petitioner shall file tariffs with the Electric Division of the Commission, prior to placing into effect the rates and charges authorized herein and in conformity with the Commission's rules for filing of utility tariffs and this order.

4. Petitioner shall be and hereby is authorized to place into effect for accrual accounting purposes the depreciation accrual rates as indicated above in section 7 and as otherwise stated in this order.

5. The accounting authorities sought by Petitioner shall be and hereby are denied or approved in accordance with Findings No. 8B(1) respecting authority to defer return on Cook Unit 1 turbine (approved) and Finding No. 10C(5) respecting major storm expense reserve (denied).

6. Petitioner shall be and hereby is authorized to implement the Capacity Tracker in accordance with Finding No. 10.

7. The information filed by Petitioner in this Cause pursuant to its Motions for Protective Order is deemed confidential pursuant to I.C. § 5-14-3-4 and I.C. § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

**ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR;**

**APPROVED:**

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

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Brenda A. Howe,
Secretary to the Commission