ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, INC. FOR APPROVAL OF (1) ITS PROPOSED DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS FOR 2016-2018, INCLUDING COST RECOVERY, LOST REVENUES AND SHAREHOLDER INCENTIVES IN ACCORDANCE WITH IND. CODE §§ 8-1-8.5-3, 8-1-8.5-10, 8-1-2-42(a) AND PURSUANT TO 170 IAC 4-8-5 AND 170 IAC 4-8-6; (2) AUTHORITY TO DEFER COSTS INCURRED UNTIL SUCH TIME THEY ARE REFLECTED IN RETAIL RATES; (3) RECONCILIATION OF DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAM COST RECOVERY THROUGH DUKE ENERGY INDIANA, INC. STANDARD CONTRACT RIDER 66A; AND (4) REVISIONS TO STANDARD CONTRACT RIDER 66A	CAUSE NO. 43955 DSM 3 APPROVED: MAR 16 2016

NUNC PRO TUNC ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Administrative Law Judge

On March 9, 2016, the Commission issued an Order in this Cause. The Order errantly indicated that Vice-Chair Carolene Mays-Medley was voting to approve the Order. Therefore, the Order should be amended nunc pro tunc to reflect her dissent. A revised copy of the March 9, 2016 Order with the dissent attached is included with this Order.

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

1. The March 9, 2016 Order in this Cause shall be amended to include the attached dissent.

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

STEPHAN, HUSTON, MAYS-MEDLEY, AND ZIEGNER CONCUR; WEBER NOT PARTICIPATING:

APPROVED: MAR 16 2016

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

Shala M. Coe

Shala M. Coe
Acting Secretary to the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, INC. FOR APPROVAL OF (1) ITS PROPOSED DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS FOR 2016-2018, INCLUDING COST RECOVERY, LOST REVENUES AND SHAREHOLDER INCENTIVES IN ACCORDANCE WITH IND. CODE §§ 8-1-8.5-3, 8-1-8.5-10, 8-1-2-42(a) AND PURSUANT TO 170 IAC 4-8-5 AND 170 IAC 4-8-6; (2) AUTHORITY TO DEFER COSTS INCURRED UNTIL SUCH TIME THEY ARE REFLECTED IN RETAIL RATES; (3) RECONCILIATION OF DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAM COST RECOVERY THROUGH DUKE ENERGY INDIANA, INC. STANDARD CONTRACT RIDER 66A; AND (4) REVISIONS TO STANDARD CONTRACT RIDER 66A	CAUSE NO. 43955 DSM 3 APPROVED:

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Administrative Law Judge

On May 28, 2015, Duke Energy Indiana, LLC ("Petitioner" or "Company") filed its Petition with the Indiana Utility Regulatory Commission ("Commission") initiating this Cause. In its Petition, the Company requested: approval of a comprehensive portfolio of demand side management and energy efficiency programs for all eligible participants; accounting and ratemaking authority to recover associated program costs, lost revenues, and a shareholder incentive (for all programs except for the low-income weatherization program); approval of its reconciliation of the costs incurred (including lost revenues) for both Core and Core Plus Programs and incentives achieved (for Core Plus Programs only) during 2014 with amounts actually collected from customers from Standard Contract Rider No. 66A ("Rider EE") billings; approval of its updated reconciliation of lost revenues for 2012 and 2013 pursuant to the Settlement Agreement approved in Cause No. 43955 DSM-1 ("DSM-1"); authority to adjust Rider EE accordingly; and continued authority to use deferred accounting on an ongoing basis until such costs are reflected in retail rates.

On May 28, 2015, Petitioner filed its case-in-chief testimony, along with a Motion for Protection of Confidential and Proprietary Information and a Petition and Request for Administrative Notice. On June 16, 2015, the Presiding Officers issued Docket Entries finding that Petitioner's confidential and proprietary information should be held as confidential on a preliminary basis, and granting Petitioner's request for administrative notice. On July 6, 2015, the

Presiding Officers issued a Docket Entry establishing an agreed upon procedural schedule for this proceeding. On June 1, June 11, and July 17, 2015, respectively, the Citizens Action Coalition of Indiana, Inc. ("CAC"), Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), and the Duke Energy Indiana Industrial Group ("Industrial Group") filed Petitions to Intervene in this proceeding. The Commission granted those Petitions to Intervene on June 16, June 17, and July 29, 2015, respectively.

On September 25, 2015, Petitioner filed its Unopposed Motion to Amend Petition to include Ind. Code § 8-1-8.5-10 as statutory authority. On October 7, 2015, the Commission entered a Docket Entry granting Petitioner's Motion to Amend its Petition.

An evidentiary hearing was held in this Cause on October 13, 2015, at 9:30 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the parties offered their respective pre-filed testimony, all of which were admitted into the evidentiary record, and the witnesses were subject to cross examination. No members of the public appeared.

The Commission, having considered the evidence and applicable law, finds as follows:

1. **Notice and Commission Jurisdiction.** Notice of the hearing in this Cause was given as required by law. Petitioner is a "public utility" within the meaning of Indiana Code § 8-1-2-1 and an "electricity supplier" within the meaning of Ind. Code § 8-1-8.5-10(a). Pursuant to Ind. Code §§ 8-1-2-4, 8-1-2-42, Ind. Code ch. 8-1-8.5, and 170 IAC 4-8, the Commission has jurisdiction over Petitioner's DSM program offerings and associated cost recovery. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Petitioner is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public, including the central, north central and southern parts of the State of Indiana. It also sells electric energy for resale to municipal utilities and to other public utilities that, in turn, supply electric utility service to numerous customers in areas not served directly by Petitioner.

3. **Applicable Rules and Statutes.** The Commission has developed a regulatory framework that allows a utility to meet long-term resource needs with both supply-side and demand-side resource options in a least-cost manner. As part of its Integrated Resource Plan ("IRP"), an electric utility must consider alternative methods of meeting future demand for electric service, including a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. 170 IAC 4-7-6(b). The Commission adopted 170 IAC 4-8 providing guidelines for DSM cost recovery ("DSM Rules"). The DSM Rules were specifically designed to assist the Commission in its administration of the Utility Powerplant Construction Act, Ind. Code ch. 8-1-8.5, and to facilitate increased use of DSM as part of the utility mix. This regulatory framework acknowledges the possibility of financial bias against DSM, recognizes the need to evaluate the extent of any bias, and provides ways for the Commission to eliminate any bias through adoption of a package of cost recovery

and incentive mechanisms designed to facilitate the use of DSM to meet the long-term resource needs of customers.

Ind. Code ch. 8-1-8.5, the statutory authority for both the Commission's DSM and IRP Rules, establishes a least-cost standard for issuances of certificates of public convenience and need prior to construction of electric generation facilities. We have previously defined "least-cost planning" as a "planning approach which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *PSI Energy, Inc.*, Cause No. 42145, at 4 (IURC Dec. 19, 2002) (quoting *Southern Indiana Gas & Electric Co.*, Cause No. 38738, at 5 (IURC Oct. 25, 1989)). Public utilities are thus to exercise reasonable judgment as to how best meet the obligation to serve within the context of the least-cost standard. *PSI Energy, Inc.*, Cause No. 39175, at 3-4 (IURC May 13, 1992).

Ind. Code § 8-1-8.5-9 ("Section 9"), which became law on March 27, 2014, allows an electric utility to offer a cost-effective portfolio of energy efficiency programs to customers, and, if the Commission determines that the portfolio is reasonable and cost-effective, to recover energy efficiency program costs in the same manner as such costs were recoverable under Cause No. 42693 S1 ("Phase II Order"). It also creates the ability for certain industrial customers to opt out of participation in an electric utility's energy efficiency program.

Ind. Code § 8-1-8.5-10 ("Section 10"), which became law on May 6, 2015, mandates the periodic filing, beginning no later than 2017 and not less than once every three years, of plans by electricity suppliers that include energy efficiency goals, energy efficiency programs to achieve the goals, program budgets and program costs, and EM&V procedures that must include independent EM&V. Upon submittal of a plan, the Commission is required to consider ten factors in determining the overall reasonableness of a plan. If the Commission finds a plan to be reasonable in its entirety, the Commission shall: (1) approve the plan in its entirety, (2) allow the electricity supplier to recover all associated program costs on a timely basis through a periodic rate adjustment mechanism, (3) allocate and assign costs associated with a program to the class or classes of customers that are eligible to participate in the program, and (4) allow recovery of reasonable performance incentives and lost revenues. If the Commission finds the plan is not reasonable because costs associated with one or more programs included in the plan exceed the projected benefits of the program(s), the Commission may exclude the program(s) and approve the remainder. And, if the Commission finds the plan is not reasonable in its entirety, then the Commission's order shall set forth the reasons for its determination and the electricity supplier shall submit a modified plan within a reasonable time.

It is against the backdrop of the Commission's Rules and Indiana statutes that we consider the DSM programs and ratemaking proposals made by Petitioner in this Cause.

4. **Requested Relief.** In its Petition, the Company requested approval of a comprehensive portfolio of energy efficiency programs for all eligible participants. Petitioner also requested accounting and ratemaking authority to recover associated program costs, lost revenues, and a shareholder incentive.

Petitioner also sought approval of its reconciliation of the costs incurred (including lost revenues) for both Core and Core Plus Programs and incentives achieved (for Core Plus Programs only) during 2014 with amounts actually collected for customers from Rider EE billings. Pursuant to the Settlement Agreement approved in DSM-1, Petitioner also sought approval of its updated reconciliation of lost revenues for 2012 and 2013.

Finally, Petitioner sought authority to adjust Rider EE accordingly and continued authority to use deferred accounting on an ongoing basis until such costs are reflected in retail rates.

5. **Petitioner's Case-in-Chief.** Petitioner presented the testimony of four witnesses in its case-in-chief: Mr. Michael Goldenberg, Manager, Customer Planning and Regulatory Strategy for Petitioner; Ms. Roshena M. Ham, Manager, Measurement and Verification for Petitioner; Ms. Karen K. Holbrook, Director, Program Performance for Petitioner; and Ms. Diana L. Douglas, Director, Rates & Regulatory Planning for Petitioner.

In his testimony, Mr. Goldenberg addressed Senate Enrolled Act 412 ("SEA 412"), codified in part at Ind. Code § 8-1-8.5-10, and the effect it has on Petitioner's Energy Efficiency ("EE") filing this year; the outcome of opt-out that resulted from Senate Enrolled Act 340 ("SEA 340"); an overview of Petitioner's EE portfolio performance relative to the target reductions from the Phase II Order; and a description of Petitioner's 2016-2018 proposal for its EE portfolio, including the programs and cost recovery mechanism. Mr. Goldenberg further explained that Petitioner was seeking, in its filing, approval of the following: reconciliation of 2014 program costs, including lost revenues and performance incentives; its 2016-2018 portfolio of programs; recovery of associated program costs including lost revenues; a revised Cost Plus performance incentive mechanism; changes to its Oversight Board ("OSB") Governance Bylaws; and its proposed 2016 EE Rider rates.

With regard to SEA 412, Mr. Goldenberg testified that this new statute guides Petitioner's post-2014 EE filings regarding the frequency of such filings, the nature of cost recovery, the ability to earn a shareholder incentive, and how Petitioner's portfolio will be informed by the Company's Integrated Resource Plan ("IRP"). Mr. Goldenberg also testified as to the opt out provisions in SEA 340. He testified that over 80% of the eligible load of industrial customers have opted out, which is approximately 49% of the total Commercial and Industrial load for Petitioner. As such, Petitioner modeled program participation and impacts associated with its Non-Residential Smart Saver® Prescriptive and Custom programs factoring in the opt-out results.

Mr. Goldenberg also testified as to Petitioner's overall performance as to its Phase II Order EE targets in 2014. He testified that Core Programs that were offered by the third party administrator ("TPA") continued to underperform reaching only 63% of their portion of the bifurcated target. In 2014, the Core programs produced impacts of nearly 167,000 MWH with nearly 80% coming from Residential Lighting and Commercial and Industrial ("C&I") Rebate Programs. For the Core Plus programs, impacts were over 86,000 MWH in 2014 with over 80% generated by the My Home Energy Report, C&I Prescriptive Rebate and C&I Custom Rebate programs. This is an achievement level of approximately 105% of the target, earning a 12% incentive on eligible program costs, using the incentive mechanism approved in the DSM-1 proceeding.

Mr. Goldenberg testified that Petitioner was proposing that its 2016-2018 EE plan would contain the same programs approved by the Commission in Cause No. 43955 DSM-2 ("DSM-2"), along with modifications of existing programs and some new programs.

Mr. Goldenberg testified that Petitioner was proposing these programs based on the following six main criteria: (1) the performance of the current portfolio of programs being offered to Petitioner's customers in 2015; (2) an opportunity to go further into its C&I vertical markets such as retail, education, distribution and small commercial/industrial in an effort to offset a part of the effects of opt-out approved in SEA 340; (3) an opportunity to open up new channels of marketing for existing and new measures in the Residential market; (4) advancements in technology; (5) the changing market place for both residential and non-residential customers; and (6) program experience in other jurisdictions. By using these criteria, Petitioner has the ability to determine what cost effective programs have been most successful, to ensure the most comprehensive coverage of its divergent customer mix and to utilize the most up to date go-to-market strategies.

Mr. Goldenberg testified that, in this filing, Petitioner was offering new programs for both its Residential and C&I customers. For Residential, the following programs are new additions or modifications to its EE portfolio: Smart $aver® Residential, Low Income Weatherization, and Power Manager for Apartments. For C&I customers, the following programs have been added to the portfolio: Small Business Energy Saver and Power Manager for Business.

Mr. Goldenberg testified that the EE portfolio was cost effective and that all programs were cost effective using the Utility Cost Test ("UCT"), except the low-income Weatherization Program. This program offers 2 tiers of measures depending upon the customer's needs. It also offers a $250.00 allotment for health and safety for every home in Tier 2 and includes a refrigerator replacement component. Even though the program did not pass the UCT, Mr. Goldenberg stated that there are benefits to bringing these needed improvements to low-income customers and offering EE programs to this group of customers, especially where the entire EE program portfolio remains cost effective under the UCT.

Mr. Goldenberg testified that Petitioner is confident in the process it undertook to develop its 2016-2018 portfolio budget and programs, because it has more in-depth knowledge of how the market is responding to the program now versus in 2014 when it was formulating its 2015 portfolio. Petitioner used historical program performance, as well as data from other jurisdictions in which it operates, to develop the types of programs and measures that should be well received in Indiana. Program managers then used their experience in the marketplace to determine the likely level of participation, taking into consideration historical program offerings, market saturation, and delivery methods that are new to Indiana. These participation assumptions drove the proposed EE budget on a measure and program basis, resulting in the overall portfolio budget.

Mr. Goldenberg also testified that since Petitioner's 2013 IRP was filed, the energy efficiency landscape has changed considerably. Two major changes have occurred since 2013: (1) the ability for large industrial and commercial customers to opt out of a utility's EE programs; and (2) the elimination of the generic Phase II mandated goals. In comparing the proposed EE plan in this filing to the 2013 IRP EE assumptions, Mr. Goldenberg observed that Petitioner's EE plan is more consistent in the near term with the IRP scenario that showed lower spending and impacts for EE. Additionally, Petitioner's EE plan cost-effectiveness analysis, used to help Petitioner determine the programs and measures to pursue, uses avoided energy and capacity costs that are consistent with the avoided energy and capacity costs used in its IRP analysis, further demonstrating that Petitioner's EE plan is informed by and consistent with its prior IRP analysis. Mr. Goldenberg added that, consistent with the Commission's regulations, Petitioner would be filing its next IRP in November 2015; and in 2016, it would review how the budget and impacts in this current EE plan portfolio compare with the Petitioner's new IRP analysis. Petitioner also plans to provide information on this to both the OSB and the Commission in future EE filings.

Mr. Goldenberg testified that, in this filing, Petitioner is seeking recovery of costs, lost revenues, and a performance incentive. With respect to Petitioner's proposal for lost revenue recovery, consistent with the settlement agreements approved in Petitioner's DSM-1 and DSM-2 cases, Petitioner is seeking recovery of lost revenues for the shorter of the life of the measure or until revenues are updated in a subsequent retail base rate case. The Company is seeking lost revenue recovery because customers receive the benefits of EE through their immediate bill savings and lower electric rates. At the same time, Petitioner's promotion of its EE programs causes it to experience a reduction in the recovery of its fixed costs absent the recovery of lost revenues. Lost revenues are a mechanism to make a utility whole between rate cases. Mr. Goldenberg testified that approximately 19 other states utilize lost revenue recovery mechanisms. Without such a mechanism, there would be a strong disincentive for any utility to aggressively pursue EE programs.

Mr. Goldenberg testified that a performance incentive is appropriate pursuant to the Commission rules. Furthermore, he stated that shareholder incentives help to put demand-side resources on an equal footing with supply-side resources. Also, shareholder incentives provide an incentive to pursue cost-effective energy efficiency.

Mr. Goldenberg testified that, in this filing, Petitioner is seeking to continue with a cost plus shareholder mechanism, as approved in DSM-2, but with several simplifying revisions to the most recently approved mechanism. Mr. Goldenberg explained that the incentive mechanism approved for use for 2015 programs in DSM-2 included performance tiers with scaled percentages earned based on the performance tier achievement, along with a cap and floor. In this proceeding, Petitioner proposes that the Company earn a 12% pre-tax return on its approved program costs, with a minimum performance requirement of 70%. This means that if Petitioner fails to achieve 70% of the EE savings projected by its portfolio, it would not earn any incentive. Petitioner's projections will be the basis for this calculation and are measured as gross MWh at the plant. Petitioner is also proposing that its incentive will not exceed 12% of 115% of the sum of the budgets for its approved portfolio. Further, all programs that fail the UCT and all pilot programs are excluded from the incentive calculation.

Mr. Goldenberg supported the elimination of the performance incentive tiers in this filing, by noting that the elimination of tiers keeps the incentive on a level playing field and does not penalize the Company for an unanticipated occurrence (such as opt out) that leads to less than 100% attainment of goals.

Mr. Goldenberg testified that Petitioner is still maintaining the OSB as approved in DSM-2 and continues to have monthly phone calls and quarterly in-person meetings to review the performance scorecard. Petitioner is proposing in this filing that the OSB have the discretion to approve program spending up to 15% of the total budget associated with its approved programs without filing with the Commission for approval. Currently, Petitioner must file for any additional funding, which presents difficulties when a program is performing better than expected and needs an increase in budget to continue to offer the program through year end. By empowering the OSB to approve these expenditures, it will eliminate the need to file and await Commission approval. It will also allow Petitioner and the OSB to respond more quickly to market conditions.

Mr. Goldenberg also testified that, in this filing, it is seeking approval for funding of a Market Potential Study ("MPS") in 2016. Petitioner's most recent MPS was completed in January 2014 and, at that time, it was anticipated that the Phase II Order would continue through 2019. Additionally, Cause No. 44310 was under consideration and there was no SEA 340 and no opt out at that point in time. As a result, the study has very limited use at this time and a new study would be informative going forward. Petitioner has included in the budget $300,000 for the study and is proposing that it would be recovered contemporaneously as a program cost. If funding is approved, Petitioner will work with the OSB on the RFP process and jointly oversee the delivery of a final report.

Mr. Goldenberg concluded his testimony by stating that this proposed 2016-2018 plan is the next best step for the Petitioner following the transition year of 2015, which included SEA 340, SEA 412, and the closing of Energizing Indiana. Petitioner has been able to assess the impacts resulting from all of these initiatives and is confident that its portfolio reflects paths to capitalize on the opportunities and overcome the gaps that are attributable to these changes. Petitioner also believes that the modifications being requested in the OSB By-Laws and incentive mechanism reflect the effort it continues to put forth in providing its customers expanded program offerings in conjunction with the potential to lower their energy bills.

On July 21, 2015, Mr. Goldenberg supplemented his testimony (as entered into evidence as Petitioner's Exhibit 2) to clarify Petitioner's EE plan as it conforms to SEA 412. As Mr. Goldenberg testified, SEA 412 requires a utility file an EE plan not less than one time every three years and the EE plan must include the following: (1) goals, (2) programs, (3) budget and program costs, and (4) an EM&V plan. Mr. Goldenberg stated that Petitioner's prior direct testimony outlined all SEA 412 requirements, but did not make clear Petitioner's specific goals as part of its plan. As such, Mr. Goldenberg testified regarding Petitioner's goals for 2016-2018. Mr. Goldenberg further testified that, in his opinion, these goals are reasonably achievable because in prior years (2012-2014), Petitioner and Energizing Indiana exceeded the total proposed in this filing.

Ms. Ham testified about Petitioner's EM&V procedures and cost-benefit analysis that EM&V involves documenting program benefits or impacts and program effectiveness, which encompasses data collection, monitoring, and analysis associated with the calculation of gross energy and demand savings from individual sites/projects and can be a subset of program evaluation. Not only is EM&V necessary to comply with Commission rules and orders, but Petitioner believes that EM&V is required for successful, reliable and cost-effective EE programs.

EM&V reliably measures savings achieved from EE, thus providing certainty for resource planning and provides accountability to customers and shareholders. Further, properly executed evaluation activities support program improvements. Understanding savings estimates and program efficacy enables Petitioner to drive increased energy savings through improved design, including insights on the targeting and marketing of specific programs to improve overall participation and cost-effectiveness.

Ms. Ham explained that Petitioner utilizes five types of evaluations: (1) Cost Effectiveness Evaluation – requires establishing a set of projected expected impact assumptions before program implementation; (2) Impact Evaluation – estimates the actual energy and demand load reductions realized from a program through such methods as billing analysis, engineering analysis, or statistically adjusted engineering models; (3) Measurement – metering, sub-metering, hours-use logger meter, statistical pre and post analyses, or other modes of measuring load reduction (measurement is usually a subset of an impact evaluation); (4) Verification – confirmation that customers actually installed the intended measures, that vendors are performing to expectation, and operational factors on the customer site are occurring such that expected load savings are being realized; and (5) Process Evaluations – review and auditing methods that ascertain program effectiveness, customer satisfaction and experience, vendor satisfaction, and other factors that contribute to program success.

Ms. Ham testified that Petitioner will measure, monitor and verify its program performance as was previously presented and approved in Cause No. 43955. Implementation of this approach is in process for the Core Plus programs and programs included in the 2015 portfolio. Attachment B-1 (as entered into evidence as Petitioner's Exhibit 4) to Ms. Ham's testimony provided an initial design for the EM&V analysis for the proposed EE programs.

Ms. Ham testified that Petitioner's proposed EM&V plans satisfy the Commission's rules and she outlined in detail how Petitioner satisfied the rules. Ms. Ham stated that, Petitioner will work with the OSB, providing draft EM&V studies and periodic updates on evaluation status and progress. Ms. Ham testified that with all the steps outlined in her testimony, Petitioner can fully satisfy the Commission's rules on evaluation.

Ms. Ham testified that the Settlement Agreement between Petitioner and the OUCC as approved by the Commission in DSM-1, required that Petitioner reconcile estimated lost revenues with actual lost revenues as verified by EM&V, applied retrospectively to the previously reconciled period for each program and required that Petitioner calculate the shareholder incentive using prospective energy savings estimates and retrospective EM&V-reconciled participation numbers. Ms. Ham testified that Petitioner proposes the same treatment in this proceeding for the 2016-2018 EE Programs.

Ms. Ham testified that the estimated cost for all EM&V over the three year portfolio would be $9,224,505,[1] approximately 9% of the total costs.

With respect to the application of EM&V to ratemaking, Ms. Ham testified that upon completion of a program impact evaluation, estimates are revised based on the impact evaluation

[1] This number was subsequently updated in Ms. Ham's rebuttal testimony, discussed *infra*.

findings. Future forecasts then incorporate the most recent EM&V results. Estimated participant and load impact information is used to develop estimates of future lost revenues, future target achievement levels for development of estimated incentives, and future cost-effectiveness evaluations. In using EM&V results in developing true-ups for the proposed Rider, Ms. Ham testified that a completed impact evaluation report would provide Petitioner with the verified participation and ex-post load impacts during the period of the evaluation study. Petitioner will then use this information as the basis for retrospective true-ups of estimated lost revenues for the proposed EE Rider. Petitioner will use this actual participation information as the basis for retrospective true-ups and the ex-post load impacts to calculate the shareholder incentive, as described in the Settlement approved by the Commission in DSM-1.

Ms. Ham testified that Petitioner provided completed EM&V reports for the following programs in Cause No. 42693 S1: Power Manager, Personalized Energy Report, My Home Energy Report, Agency Assistance Portal, Residential Multi-Family Energy Efficiency, Appliance Recycling, Residential Smart $aver HVAC, and Non-Residential Smart $aver Lighting (Core Plus Measures). The Residential Smart $aver HVAC report filed in 42693 S1 includes process evaluation only. Finalized impact evaluation is pending. Ms. Ham testified that the results of the completed EM&V reports have been incorporated for the purpose of lost revenues calculations and projections. She explained that the EM&V reports that are scheduled to be completed in 2015 will lead to retrospective true-ups for the applicable 2012, 2013 and 2014 program measures in a future EE Rider filing. In DSM-2, the Commission ordered Petitioner to file annually by July 1, its independent EM&V report concerning its 2015 EE programs with information regarding "the completed cost/benefit cost ratios for the utility cost test, total resource cost test, ratepayer impact measure test, and the participant cost test. It shall also identify the discount rate used in the cost-benefit calculations." The requested cost-benefit analysis for the 2015 EE programs will be calculated using the actual costs and benefits at the close of 2015 and will be filed on or before July 1, 2016.

Ms. Ham also explained the DSMore Model, which requires input of the specific EE measure or program, program cost, avoided costs, and rate information of the utility to calculate cost effectiveness. The analysis of EE cost-effectiveness focuses on the calculation of specific metrics, often referred to as the California Standard Tests: Utility Cost Test ("UCT"), Ratepayer Impact Measure ("RIM") Test, Total Resource Cost ("TRC") Test, Participant Cost Test ("PCT"), and Societal Cost Test ("SCT"). DSMore provides results of these tests for any type of EE program (demand response and/or energy saving).

Ms. Ham testified that the following EE program or measure information is required to be inputted into the model: (1) number of program participants, including free ridership or free drivers; (2) projected program costs, contractor costs and/or administration; (3) customer incentives, demand response credits or other incentives; (4) measure life, incremental customer costs and/or annual maintenance costs; (5) load impacts (kWh, kW and the hourly timing of reductions); and (6) hours of interruption, magnitude of load reductions or load floors. She also testified that the following utility information was required for the model: (1) discount rate; (2) loss ratio, for annual average losses; (3) rate structure, or tariff appropriate for a given customer class for a given jurisdiction; (4) avoided costs of energy, capacity, transmission & distribution; and (5) cost escalators.

Ms. Ham testified that the Program Managers and Analysts develop the initial inputs for each program/measure from industry information derived from sources such as Electric Power Research Institute ("EPRI"), Energy Star, E-Source, other utility program information and evaluations, Indiana and other contiguous states' Technical Reference Manuals ("TRM"), engineering building simulation models, as well as from external experts in the industry. The Indiana TRM, version 1.0, was prepared by the Indiana Statewide Evaluation Team, led by TecMarket Works, for the Indiana DSMCC EM&V Subcommittee and completed January 10, 2013. Over time, as impact and process evaluations are performed on Indiana programs, information and input specifically related to Indiana customers is used for future cost-effectiveness analyses. Some of the programs being proposed by Petitioner in this filing involve measures that are either not addressed by the Indiana TRM or are substantially different from a measure in the Indiana TRM. In those cases, other data sources must be relied upon.

Ms. Ham also testified as to how EE programs and measures are analyzed. She advised that the net present value of the financial stream of costs versus benefits is assessed, *i.e.*, the costs to implement the measures are valued against the savings or avoided costs. The resultant benefit/cost ratios, or tests, provide a summary of the measure's cost-effectiveness relative to the benefits of its projected load impacts. The PCT is the first screen for a program or measure to make sure a program makes economic sense for the individual consumer. This is critical because participation by the customer in a particular EE program is voluntary and the customer is unlikely to participate unless it makes economic sense. The Petitioner also reviews the UCT, the TRC, and the RIM Tests for a comprehensive screening of energy efficiency measures. Ms. Ham explained these tests are as follows: the PCT compares the benefits to the participant through bill savings and incentives from the utility, relative to the costs to the participant for implementing the energy efficiency measure. The costs can include incremental equipment and installation costs, as well as, increased annual operating cost, if applicable. The UCT compares benefits (avoided energy and capacity related costs) to utility costs incurred to implement the program such as marketing, customer incentives, and measure offset costs, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs and load (line) losses. The TRC compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the PCT; however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC. The RIM test or non-participation test indicates if rates increase or decrease over the long-run as a result of implementing the program.

Ms. Ham further testified that the use of multiple tests can ensure the development of a reasonable set of EE programs and indicate the likelihood that customers will participate. It should also be noted that none of the tests described above include external benefits to participants and non-participants that can also offset the costs of the programs.

Ms. Ham concluded her testimony by stating, in her opinion, the programs being offered are cost effective and that Petitioner's EM&V plan is reasonable.

Ms. Holbrook testified that her group was responsible for determining the actual costs for Core and Core Plus programs used in the 2014 reconciliation, including impacts (kWh and kW), program costs, EM&V costs, lost revenues, and applicable utility incentives. Per the Settlement Agreement approved by the Commission in DSM-1, Petitioner applied EM&V where applicable for the reconciliation of lost revenues. The components of the 2014 results were provided to Ms. Douglas for her use in completing the reconciliation and calculating rates and can be found in Attachment Exhibit C-1 to Ms. Holbrook's testimony (as entered into evidence as Petitioner's Exhibit 7).

Ms. Holbrook also testified as to how the 2014 lost revenues for the Core Programs were determined. She explained that in calculating lost revenues for the residential Core Programs, her group started out with DSMore files representing a single participant with the impacts for each (kWh and kW) at the meter, net of free riders. For measures with completed EM&V, the impacts reflect any changes applied retrospectively per the Final Order in DSM-1. Actual participation was provided by GoodCents, the TPA, and captured by rate schedule in Petitioner's participation database back to the beginning of the program in January 2012 and then confirmed by her group and program management. Her group then multiplied the impacts per participant by the participation in each measure to calculate the annual and monthly kWh and kW, and then applied the appropriate lost revenue rate (or average rates when participation by rate schedule was not available) to the monthly kWh to derive the lost revenue amount for each program. These monthly calculations will be extended out for the measure life pursuant to the Final Order in DSM-1. In regard to the non-residential programs, the TPA sent monthly customer level impacts (kWh and kW) from the previous month at the meter, gross of free riders. For measures that had completed EM&V, the impacts reflect any changes, including free ridership, applied retrospectively. The customer level information was used to determine the appropriate rate schedule. Ms. Holbrook's group then applied the appropriate lost revenue rate or average rates when participation by rate schedule was not available, to the monthly kWh and kW to derive the lost revenue amount for each program. The monthly calculations will be extended out for the measure life.

Ms. Holbrook also explained how the 2014 Core Plus Program Costs were determined. Program Managers review costs charged to their programs on a monthly basis. For purposes of the 2014 reconciliation, Ms. Holbrook's group took all relevant charges recorded to the Core Plus programs in 2014 from the General Ledger and categorized them as shown on Attachement C-1 to her testimony (as entered into evidence as Petitioner's Exhibit 7). They were also categorized as to whether or not they were eligible for simple cost recovery or cost recovery plus earned shareholder incentive, based on the program to which they relate. Ms. Holbrook also testified that all Core Plus programs are eligible for a shareholder incentive with the exception of the EMIS pilot and the Residential DR Program.

Ms. Holbrook explained how the 2014 lost revenues for the Core and Core Plus programs were determined. Her group began with the DSMore files representing a single participant with the impacts for each participant (kWh and kW) at the meter, net of free riders. For measures that underwent EM&V, the impacts reflect any changes applied retrospectively. Actual participation was captured by rate schedule in Petitioner's participation database and confirmed by Program Managers. Ms. Holbrook's group then multiplied the impacts per participant by the participation in each measure to calculate annual and monthly kWh and kW and then applied the appropriate lost revenue rate (or average rates when participation by rate schedule was not available) to the monthly kWh and kW to derive the lost revenue amount for each program. These monthly calculations will be extended out for the measure life.

Ms. Holbrook also explained the term "single participant" and why it was used. For purposes of calculating actual impacts, her group receives a DSMore file that calculates the impacts achieved for a single (or each) participant. Impacts from this "single participant" file are then multiplied by actual participation to calculate monthly impacts used to calculate lost revenue and achievement level for purposes of determining shareholder incentive amounts. These impacts reflect EM&V applied as approved in DSM-1. Ms. Holbrook testified that Petitioner achieved a level sufficient to earn an incentive of twelve percent (12%) of program costs for programs eligible for incentives.

Ms. Holbrook explained that she performed other calculations for the reconciliation of the 2014 costs. As a result of the April 1, 2014, opt-out of certain qualifying non-residential customers, it was necessary to identify Non-Residential Energy Efficiency Program Costs ("NREEPC") that were "accrued or incurred or relate to energy efficiency investments made before the date on which the opt out is effective," for which qualifying customers would remain responsible. To do this, Petitioner utilized data in its accounting and invoicing systems, as well as information provided by invoicing vendors. First, NREEPC were separated into two groups: costs recorded prior to April 1 (which qualifying customers are responsible for) and costs recorded on or after April 1 (which qualifying customers may or may not be responsible for). Next, Petitioner reviewed invoices and other data regarding NREEPC that were recorded on or after April 1 to identify and isolate charges that qualifying customers are still responsible for, including costs related to energy efficiency incurred before April 1, but not reflected in the ledger by that date (such as EM&V and rebates/incentives paid for applications that had not closed out as of April 1). These charges were then assigned to the group of costs incurred prior to April 1 that qualifying customers remain responsible for paying. Incentives were also calculated and assigned to those programs eligible for incentives based on the split of costs between the two time periods. In addition to costs and incentives, Lost Revenues attributable to the participation in 2014 were also split between participation prior to and after April 1. The allocation of the costs to qualifying customers, by category was shown in Attachment C-2 (as entered into evidence as Petitioner's Exhibit 7).

Ms. Holbrook further testified that there is a potential for updates to the program costs assigned to the April 1, 2014 opt out group for the Core programs. Petitioner's Tariff states that it is to use the application date as the key to which incentive costs are to be included in the allocation of costs to qualifying customers. For this filing, the application date was not available; therefore, for the Core programs, the cutoff date used was March 31, 2014, the date of the wire transfer invoice from GoodCents. In the next reconciliation to be filed in 2016, Petitioner will have

GoodCents provide it with the application dates for all wire transfers from April 2014 through March 2015. From that date, Petitioner will be able to ascertain which additional amounts applicable to application dates made on or before March 31, 2014, need to be assigned to the April 1, 2014 qualifying customers and can add them in as part of the reconciliation. Petitioner will also have to do this same type of review and reassignment of costs for qualifying customers in next year's filing, because when Petitioner reconciles 2015 costs next year, it will need to identify any Core or Core Plus costs that need to be assigned to the second group of qualifying customers under the terms of the Tariff. Ms. Holbrook testified that this is a reasonable process and one that ensures that each group of non-residential customers is paying for the appropriate EE costs under the terms of the Tariff and in accordance with the statute.

Ms. Holbrook testified that her group was responsible for determining the actual costs for Core and Core Plus programs used in the original 2012 and 2013 reconciliations, including: impacts (kWh and kW); program costs; EM&V costs; lost revenues; and applicable utility incentives, consistent with the processes and mechanisms approved in DSM-1. Her group modified the amount claimed for the portfolio costs in 2012 due to retrospective application of EM&V to lost revenues and also modified the amount claimed for the portfolio costs in 2013 due to retrospective application of EM&V to lost revenues, updated lost revenue rates, and the addition of December 2013 Smart $aver® Custom participants that were not captured in the original reconciliation. Her group compiled the 2012 and 2013 results and compared them to the amount originally filed as shown on her Exhibits C-3 and C-4 (as entered into evidence as Petitioner's Exhibit 7), which outline the original and revised kWh and lost revenue amounts.

Ms. Holbrook also testified that her group was responsible for compiling the forecast for the 2016-2018 portfolio, including: impacts (kWh and kW); program costs; EM&V costs; lost revenue; and applicable utility incentives. Petitioner's EE program managers compiled forecasts to reflect what participation they believed to be achievable for each program, then the program managers' forecasts were informed by general participation trends experienced in other jurisdictions, expert insights from third-party vendors, and the performance to date of Petitioner's portfolio. Based on this information, program managers then provided a projection of the detailed participation and cost estimates for each program. Once Ms. Holbrook's group received the forecasted participation and costs, they applied the costs and impacts per participant from DSMore files for each measure to the forecasted participation, which gave total program costs and impacts. An overhead amount was then added based on the historical relationship of overhead costs to program costs and forecasted EM&V costs were also added. Costs were then categorized between those eligible for cost recovery only and those eligible for cost recovery plus an incentive.

Ms. Holbrook testified that she calculated Petitioner's incentive to reflect a 12% return on total eligible costs, assuming portfolio performance at 100% of target, for each of the programs eligible for performance incentives. She grouped measures into the programs as outlined in her Attachment C-5 (as entered into evidence as Petitioner's Exhibit 7). This shareholder incentive was added to the program costs and EM&V for all programs eligible for performance incentives, in order to calculate the input to the revenue requirement provided to Ms. Douglas for 2016 rate development purposes. Ms. Holbrook further testified that all programs are eligible for an incentive with the exception of Low Income (Weatherization), which Petitioner is proposing be eligible for cost recovery and lost revenue only. Additionally, costs for the 2016 MPS were added to the portfolio with no incentive included.

Ms. Holbrook testified that the 2016-2018 lost revenues were calculated by using the impacts calculated as outlined above and using forecasted participation and impacts per participant; she calculated the kWh eligible for lost revenue from 2016-2018 participation at the meter, net of free riders. Because it is not known under what rate schedules forecasted participation will occur, weighted average lost revenue rates for residential and non-residential programs based on the 2014 participation in the Core and Core Plus programs were applied. A half-year convention was used to reflect how impacts would be achieved throughout the year; and the lost revenue associated with participation since 2012 through March of 2015, as well as the forecasted participation for the remainder of 2015 calculated for the life of measure, was added. For forecasted lost revenue for the remainder of 2015, her group used internal participation forecasts and the same weighted average rates in 2015 that were used for the 2016-2018 forecasted participation discussed above. Ms. Holbrook further testified that in her opinion, the cost estimates she discussed in her testimony, which were given to Ms. Douglas for her calculations, were reasonable.

Ms. Douglas testified that, as approved in the Commission's Orders in Cause Nos. 43079 DSM-6, 44441, 43955, 43955 DSM-1, and 43955 DSM-2, all customers and rate classes are charged for the cost of a vintage year's EE programs to the extent they are or were eligible to participate in the programs offered for that period. Costs for a vintage year's programs may extend beyond that vintage year or the time customers were eligible to participate in the programs, such as in the case of persisting lost revenues or for the costs of EM&V performed in a subsequent year for a prior vintage year's programs. The ratemaking approved by the Commission for the EE Rider provides that residential customers pay for the cost of residential programs and non-residential customers pay for the cost of non-residential conservation programs for which they are or were eligible to participate. Petitioner sets rates using estimates of the costs (including lost revenues) and performance incentives based on expected achievement levels (using an expectation of 100% achievement of target), and the amounts billed to customers will be reconciled or "trued-up" to actual costs and energy savings achievements.

Ms. Douglas further testified that Petitioner was proposing certain changes to the ratemaking in this filing. For non-residential demand response programs approved to be recovered in the EE Rider, the ratemaking methodology approved for such programs in previous Orders provided for a further allocation of the demand response costs among the non-residential group to the rate class level based on average monthly coincident peak demand from the most recently approved base rate case (Cause No. 42359), with rates developed at the rate class level on a per kWh basis except for the HLF rate class, which would use a rate per non-coincident peak demand kW.

Ms. Douglas testified that Petitioner has made certain assumptions regarding opt outs in the development of its proposed rates. Petitioner relied on the opt out notices received from customers from the first opt out window (which closed July 30, 2014 and was effective April 1, 2014) and the second opt out window (which closed November 15, 2014, and was effective January 1, 2015). Using 2014 GWh data, the first opt out group comprised approximately 43%

and the second opt out group comprised approximately 6% of total 2014 non-residential GWh, leaving 51% of non-residential GWh as 2016 EE program participants. Petitioner has not had any customers who opted out effective April 1, 2014, opt back in for the 2016 EE program. Petitioner also has not assumed any additional opt outs will occur in the next opt out window which closes November 15, 2015 (to be effective January 1, 2016); however, Petitioner has developed rates in the event additional customers do opt out in this window removing 2016 program costs and associated lost revenues and incentives from the costs assigned to participating customers. Petitioner has also developed rates, in the event customers who opted out effective April 1, 2014, or January 1, 2015, decide to opt back in effective January 1, 2016.

Ms. Douglas also explained that, consistent with the requirements of SEA 340, customers who opt out remain responsible for EE program costs, including lost revenues, shareholder incentives and related reconciliations, that relate to EE investments made before the date on which the opt out is effective, regardless of the date which the rates are actually assessed.

In future years, these groups will continue to be responsible for their proportionate share of reconciliations and persisting lost revenues related to the 2012 and 2013 EE programs and January through March 2014 EE programs (for customers opting out effective April 1, 2014) and January through December 2014 EE programs (for customers opting out effective January 1, 2015) and 2015 EE programs (for customers opting out effective January 1, 2016). As approved by the Commission in DSM-1 and DSM-2, the lost revenues associated with the 2012–2015 program years will be included in EE Rider rates until the measure life is expired for the individual programs or until rates are effective from a base rate case. As approved, the lost revenues for these years are also subject to additional reconciliations in future years due to retrospective application of EM&V. Any qualifying customers new to Petitioner's system who sign a demand contract of more than one (1) megawatt and provide notice of opt out under the terms of the Tariff will not be responsible for any EE Rider costs.

Ms. Douglas testified that the opt out requirements affected the calculation of the 2016 proposed rates, because customers who opt out are not responsible for the same set of costs as customers who are not eligible for opt out or chose not to opt out, and because eligible customers opting out at different times are responsible for different sets of costs based on the respective effective dates of their opt outs. As such, it was necessary to calculate separate rates for each opt out group. Applicable costs, opt out load, and timing outlined above were used to develop rates for each of the opt out groups.

Ms. Douglas testified as to the 2016 proposed rates and rate impacts explaining that Ms. Holbrook provided her with the actual and estimated program costs, EM&V costs, lost revenues and incentive amounts for developing the rates. The 2016 costs also included the $300,000 MPS, the cost of which has been allocated between residential and non-residential customers using the 2014 kWh sales, excluding customers who have opted out. The costs included in the proposed rates incorporate the results of EM&V for calculating lost revenues, pursuant to the approved Settlement Agreements in DSM-1 and DSM-2. The 2014 kWh and billed revenues for the 2014 reconciliation were obtained from Petitioner's accounting records.

Ms. Douglas also sponsored exhibits that correspond to the ratemaking in this proceeding. Specifically, page 1 of Attachment D-2 of her testimony (as entered into evidence as Petitioner's Exhibit 9) shows that the total estimated costs (before conversion to revenue requirements) for 2016 EE programs, including persisting lost revenues from prior year programs, is approximately $64.7 million. Page 2 of Attachment D-2 of Ms. Douglas' testimony (as entered into evidence as Petitioner's Exhibit 9) shows the actual EE costs (before conversion to revenue requirements) in 2014 for Core programs is approximately $35.1 million and the total for Core Plus programs is approximately $19.5 million, for a total of approximately $54.6 million. Also shown on Attachment Exhibit D-2 (as entered into evidence as Petitioner's Exhibit 9) is an over-collection for 2014 of approximately $0.1 million from Residential customers, an over-collection of approximately $4.3 million from Non-Residential participating customers, an over-collection of approximately $0.2 million from Non-Residential customers who opted out effective April 1, 2014, and an over-collection of approximately $0.5 million from Non-Residential customers who opted out effective January 1, 2015, for a net over-collection of approximately $5.0 million in total for Non-Residential customers. Page 5 of Attachment D-2 (as entered into evidence as Petitioner's Exhibit 9) reflects retrospective application of EM&V for purposes of determining the amount of lost revenues to be recovered, showing the reconciliation for an additional small refund amount to both Residential and Non-Residential customers that was included in the development of 2016 proposed rates. Ms. Douglas testified that there is still some EM&V for both Residential and Non-Residential 2012 programs yet to be received and reflected in the Rider. Petitioner anticipates another reconciliation for 2012 in next year's EE Rider filing.

Ms. Douglas' Attachment D-2 (as entered into evidence as Petitioner's Exhibit 9), page 6, reflects a reconciliation of 2013 EE program lost revenues using additional EM&V results received since DSM-2, which results in a $0.3 million over-collection for Residential customers and a $0.4 million under-collection for Non-Residential customers that were included in the development of 2016 proposed rates, for a net under-collection of $0.1 million. There is still some EM&V for both Residential and Non-Residential 2013 programs yet to be received and reflected in the Rider. Petitioner anticipates another reconciliation for 2013 in next year's EE Rider filing. Page 7 of Attachment D-2 (as entered into evidence as Petitioner's Exhibit 9) contains the proposed 2016 EE Revenue Adjustment factor for Residential customers and Page 8 shows the rate development for Non-Residential customers. The revenue requirements for the non-residential rate group were allocated among the three applicable opt out groups based on what period the costs relate to and using the 2014 kWh sales for each group. The resulting revenue requirement for the costs to be recorded via the EE Rider in 2016 is approximately $39.5 million for Residential customers and $21 million for Non-Residential customers, for a total of $60.5 million. The proposed 2016 adjustment factors were developed by dividing the revenue requirement for the Residential and three Non-Residential opt out rate groups by the applicable twelve months ending the December 2014 billing cycle kWh sales amounts.

Ms. Douglas also explained that Attachment Exhibit D-3 of her testimony (as entered into evidence as Petitioner's Exhibit 9) provided information regarding the rate impact of the rate adjustment factors developed in Attachment D-2 (as entered into evidence as Petitioner's Exhibit 9). It shows that, for non-residential customers, including customers who have opted out, the 2015 rates included a large reconciliation credit for the 2013 reconciliation due to a large over-collection in 2013 of $20.2 million. This resulted in credit rates for opt out customers for 2015. The 2014 reconciliation included in these proposed 2016 rates had a much smaller level of over-collection, which resulted in rates that are an increase over what customers are currently paying. Should the Commission approve the proposed 2016 rates, Ms. Douglas testified that a typical residential customer using 1000 kWh can expect to see a $1.00 increase in their monthly bill. Ms. Douglas stated that the rate impacts shown in Attachment D-3 (as entered into evidence as Petitioner's Exhibit 9) were developed without any consideration for the positive impact to customer bills from the lower energy usage that is expected to result from participation in these programs, both in absolute individual usage reductions for those who choose to participate in program offerings and in lower overall energy usage for native load customers, which will reduce fuel and other variable production costs that are included in customer rates.

Ms. Douglas also testified that in the next EE Rider filing, planned for mid-2016, Petitioner will reconcile 2015 EE actual costs, lost revenues, and performance incentives to amounts billed for the Rider 66-A during 2015. The reconciliation is expected to include a true-up of 2015 lost revenues and performance incentives based on 2015 actual participation in the EE programs and the retrospective application of the results of applicable EM&V for lost revenue purposes.

Ms. Douglas further testified as to lost revenue pricing. In this filing, Petitioner used lost revenue pricing rates (*i.e.*, rates reflecting fixed costs embedded in base rates) that were developed for each rate schedule in the Residential and Non-Residential rate groups that had identified participation. The source of the fuel and other variable O&M adjustments was Petitioner's cost of service study approved in Cause No. 42359, and the source of the revenue and kWh data was Petitioner's billing system. Petitioner was able to obtain the participation by rate schedule data for both Core and Core Plus programs. In the few cases where rate schedule level data was not available, average lost revenue pricing rates were developed using the rate schedules most likely to be applicable to the customers served by the programs.

Ms. Douglas further testified that the lost revenue pricing rates based directly on Tariff rates or adjusted Tariff rates will not change until new base rates are approved. Lost revenue pricing rates for the block Tariff rate schedules could change year to year based on the sales of each of the Tariff block levels, as can average group rates, and will also change at the time new base rates are approved. Ms. Douglas concluded her testimony by stating that Petitioner intends to continue using the deferral accounting for EE expenses and revenues to minimize the timing difference between cost of revenue recognition on Petitioner's books and actual cost recovery.

6. <u>OUCC's Case-in-Chief</u>. The OUCC presented testimony of two witnesses in its case-in-chief: Ms. April M. Paronish, Utility Analyst in the Resource Planning and Communications Division of the OUCC (entered into evidence as Public Exhibit 1); and Mr. Edward T. Rutter, Utility Analyst in the Resource Planning and Communications Division of the OUCC (entered into evidence as Public Exhibit 2).

Ms. Paronish testified that she participated in regular OSB meetings with Petitioner to monitor DSM program effectiveness and to adjust funding and/or program design, when indicated, to achieve higher energy savings. Ms. Paronish further testified that she did not believe Petitioner's case-in-chief provided sufficient detail to determine if the DSM Plan is reasonable.

Ms. Paronish argued that Petitioner's case-in-chief omits information essential to determine program reasonableness, such as the estimated participants and estimated number of measures to be installed. Ms. Paronish testified that without this information, it is impossible to determine how projected savings are derived by program or to check the reasonableness of those calculations.

Ms. Paronish testified that Petitioner's program cost information does not specify items such as incentive amounts. She further stated that energy savings goals per program are provided as confidential information, while other utilities present this publicly. Ms. Paronish stated that she was troubled by the lack of transparency and absence of detailed information and that without detailed information on a program-specific basis, neither stakeholders nor the Commission can gauge the reasonableness of budgets and also cannot determine how projected savings are derived by program.

Ms. Paronish also testified that she believed Petitioner's methodology on the TRC Test was incorrect. She stated that the OUCC's issue is that Petitioner is incorrectly excluding certain costs from the TRC calculations, artificially inflating the results.

Ms. Paronish cites to the California Standard Practice Manual ("SPM") when addressing what benefits are properly included in the TRC calculation. Accordingly, "the benefits calculated in the TRC Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction." As to the costs included in the TRC calculation, Ms. Paronish again cites to the California SPM as, "The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, costs of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test."

Ms. Paronish cites to an example of a program for which the TRC was calculated incorrectly: Petitioner's Weatherization Program. The customer has no out-of-pocket expenses, no rebates are paid directly to the customer, and all weatherization costs are paid with program funding; therefore, all costs should be included in the TRC calculation. According to Ms. Ham's calculation on pages 23 and 24, the Weatherization Program received a TRC score of 1.12. This score can only be achieved if some costs are excluded from the calculation. As such, Petitioner improperly chose to classify some items in the Weatherization Program as incentives, rather than program costs. Ms. Paronish further claims that Ms. Ham discusses cost effectiveness and presents test scores, but includes no data or formulae that allow her results to be replicated or verified. Ms. Paronish further testified that given the lack of detail in Petitioner's case-in-chief, it is impossible to determine if Petitioner's TRC calculations for other programs use the same methodology, but such an assumption seems reasonable. TRC scores are fundamental elements of Petitioner's assertion that its programs are reasonable, and thus entitled to lost revenue and shareholder incentive recovery.

Ms. Paronish testified that the OUCC had concerns with Petitioner's proposed modifications to its Appliance Recycling Program, as no Petitioner witness has explained that Petitioner proposes reducing the incentive paid to customers that recycle their refrigerators and freezers to below the current offering of $50, but even lower than the $30 offered in early 2014.

Ms. Paronish also testified that the OUCC had concerns with Petitioner's proposed Weatherization Program in that it seeks $250 in health and safety funds for every home included in Tier 2 of its program, but the total health and safety amount requested is unclear and not DSM. Furthermore, Petitioner has not indicated how the $250 was determined nor any guidelines or parameters for use of those funds. Also, Petitioner's Attachment A-1 (entered into evidence as Petitioner's Exhibit 1), requests funding for refrigerator and furnace replacements, but there is no information specifying the total amount requested nor has Petitioner identified any criteria in determining whether to repair or replace a home's furnace. The OUCC would expect to see more details, such as refrigerator replacement cost, how Petitioner's program implementers will determine whether a refrigerator should be replaced, and whether the replacement refrigerator will be near the same cubic feet as the original refrigerator.

Ms. Paronish also testified that the timing of this program's EM&V report denies the OSB a meaningful opportunity for review as Ms. Ham's Attachment B-2 (entered into evidence as Petitioner's Exhibit 4) indicates that the EM&V report for the Weatherization Program will not be available until the fourth quarter of 2018. Because this filing covers through 2018, Petitioner will need to file for programs which would begin in 2019, before the EM&V report will be made available to the OSB. Therefore, if Petitioner offers a weatherization program in 2019, it would be designed without guidance provided by independent and objective EM&V. The OUCC recommends the proposed EM&V timing be modified to allow the OSB's final report review no later than first quarter of 2018.

Ms. Paronish also testified that the OUCC has concerns with Petitioner's EM&V Plan with its overall total budget. The estimated EM&V cost for the entire portfolio is 9% of Petitioner's total proposed program DSM budget. Ms. Paronish testified that there is a nationally recognized standard for sizing a DSM EM&V budget, the National Action Plan for Energy Efficiency ("NAPEE")'s Model Energy Efficiency Program Evaluation Guide, which suggests a range of 3 to 6% of program budgets. With Petitioner's EM&V vendor serving across all of the companies jurisdictions, Petitioner should realize economies of scale that reduce its EM&V budget. Unlike all other DSM OSB's where the EM&V vendor selection is OSB approved, Petitioner makes this decision independently. Furthermore, Petitioner does not evaluate each program every year.

Ms. Paronish testified that Petitioner is requesting the Commission authorize the OSB to approve program expenditures up to 15% above the original budget, because presently Petitioner does not have the discretion with OSB approval to spend any funds over the commission-approved budget. Allowing the OSB the ability to vote on additional funding provides Petitioner the ability to respond more quickly to market conditions. The OUCC opposes this request because the IURC has already found a 15% overspend ability unreasonable (IURC Order in Cause No. 44328 (IPL, 11/25/13)). The OUCC recommends the OSB have the authority, without additional IURC approval, to exceed the Commission-approved total DSM Plan budget by up to 10%.

Ms. Paronish also testified that the OUCC has additional requests regarding Petitioner's OSB. While the OUCC is quite pleased with most aspects of the operation of Petitioner's OSB, the OUCC makes two requests: (1) The OUCC requests Petitioner take minutes at each meeting that would capture the high-level proceedings of the meetings, decisions made (including voting), and action items, and also be approved at a subsequent meeting; and (2) OUCC seeks greater involvement in the EM&V process, including the selection of an independent vendor. Ms. Paronish also requests that Petitioner's OSB members receive the RFPs and responses and be permitted to participate in vendor presentations and voting, along with OSB members receiving copies of all EM&V reports simultaneously with Petitioner, including draft reports and vendor questions of significant impact.

Ms. Paronish testified that the OUCC objects to Petitioner's Power Manager programs being eligible for shareholder incentive recovery, because they are demand response programs not entitled to shareholder incentives. She further testified that the Commission should find that Petitioner's Power Manager programs are not "energy efficiency programs" as defined in Ind. Code 8-1-8.5-10(d)(2) and should not be eligible for recovery of either lost revenues or shareholder incentives.

Ms. Paronish recommends that the Commission find Petitioner's proposed DSM plan unreasonable in its entirety pursuant to Ind. Code § 8-1-8.5-10(m). In the event the Commission declines to find the Plan unreasonable in its entirety, it should not allocate Plan costs only to ratepayers. The Commission should consider methods to more fairly and economically share program costs with Petitioner's shareholders. In addition, the OUCC recommends that the Commission find: because of the lack of evidence in its case in chief, the Commission cannot determine whether or not Petitioner's proposed programs are reasonable; Petitioner's TRC evidence is insufficient to conclude the calculations have been made in compliance with the California Public Utility Commission's "California Standard Practice Manual"; Petitioner's Residential Appliance Recycling Program is unreasonable and should be denied; Petitioner's Weatherization Program is unreasonable and should be denied; Petitioner's EM&V budget is excessive and should be limited to not more than 5% of Commission-approved program costs; Petitioner's request for OSB authority to permit DSM program spending at 15% above Commission-approved program costs is excessive and should be denied; Beginning immediately, Petitioner shall be responsible for recording minutes at each OSB meeting; Petitioner shall fully include Petitioner's OSB in the EM&V selection process as discussed above; and Petitioner's Power Manager programs are not "energy efficiency programs" as defined by Ind. Code § 8-1-8.5-10 and thus Petitioner is not entitled to lost revenue or shareholder incentive recovery.

Mr. Rutter testified regarding the OUCC's support of Petitioner's proposed programs and budgets, exclusive of lost revenues and shareholder incentives. He described his participation in meetings, including Petitioner's OSB meetings. In said meetings, the parties discussed the policies and procedures employed in developing the proposed recovery of lost revenues and incentives.

Mr. Rutter claimed in testimony that lost revenue recovery was intended as a tool to remove the disincentive a utility would otherwise face as a result of promoting DSM in its service territory and cites to the Commission's Orders in Cause Nos. 43955 and 44514. Mr. Rutter claimed that promoting DSM within Petitioner's service territory does not expose Petitioner to any disincentive that requires removal, but rather provides an economic incentive that exceeds what the Company would earn by selecting a supply-side option. Mr. Rutter stated that the rates set in Petitioner's last rate case (Cause No. 42359, May 18, 2004) were rates set to allow Petitioner the opportunity to achieve an authorized rate of return on its rate base. He claimed that adding the UCT/Program

Administrator Cost Test ("PACT") net benefit, lost margins and incentives to the authorized Net Operating Income ("NOI") would demonstrate if a disincentive exists. If the actual return on the rate base is less than the authorized rate of return, then a disincentive exists. If the actual return on the rate base is increased, then there is no disincentive.

Mr. Rutter stated that the results of his analysis show an increase in the authorized overall rate of return in years 2017 and 2018. Mr. Rutter also claimed that adding the lost margins and incentives results in increases on the rate of return on common equity for those years as well. Therefore, Mr. Rutter claimed that implementation of Petitioner's proposed DSM Plan would not result in a disincentive to Petitioner. Mr. Rutter defined "cost-effectiveness", as used in his testimony, as a measure of the relationship between the benefits of a DSM investment and the associated costs. Results are typically developed in Net Present Value ("NPV") dollars or as a ratio of benefits/costs. A score greater than 1.0 indicates the benefits exceed the costs. He stated there are five (5) cost-effectiveness tests commonly used by state Commissions and utilities, usually with input from other stakeholders: UCT/PACT, RIM, TRC, PCT or SCT.

Mr. Rutter claimed that the UCT/PACT Test is used to determine if utility bills will increase over time. It focuses on the energy costs and benefits experienced by the utility implementing the programs. The UCT/PACT only includes the utility's cost and not the costs incurred by the customer. Neither lost margins nor shareholder incentives are included in this test. The RIM Test measures the impact on utility rates due to the changes in utility revenues and operating costs caused by a DSM program. The RIM Test does not include incentives, but is heavily influenced by lost revenues collected from all customers (participants as well as non-participants). Because the RIM Test is the only test that explicitly recognizes lost margins, more DSM programs fail to achieve a score of 1.0 for this test than the other standard tests. The TRC Test reflects total benefits and costs to all customers including the full incremental cost of the DSM measure without regard as to whether the utility or customer incurred the costs, but does not include lost revenues or incentives. According to Mr. Rutter, Petitioner's DSM Plan passed the UCT/PACT and TRC Tests, but failed the RIM Test, with the exception of the three Power Manager programs, which the OUCC argued are load control programs. The OUCC calculated the RIM Test for the overall portfolio with only four programs individually passing.

Mr. Rutter testified that the OUCC is contesting Petitioner's proposal to continue to recover lost margins from its ratepayers. Mr. Rutter argued that an imbalance exists between ratepayers and utility interest and claimed that Petitioner's proposed recovery of lost revenues and shareholder incentives are unnecessary and unreasonable.

Mr. Rutter testified that he agrees with Mr. Goldenberg's testimony, "[a]t the same time, the promotion of energy efficiency causes utilities to experience a reduction in the recovery of their fixed costs absent the recovery of lost revenues. Lost revenues are a mechanism to make a utility whole between rate cases," as it relates to the recovery of authorized fixed costs embedded in the base rates and as long as the utility does not experience sales above the pro-forma test year sales. Mr. Rutter argued that fixed costs do not change with an increase or decrease in the amount of goods or services sold and fixed costs are a component included in the base rates. Mr. Rutter argued that fixed costs are relevant, because in his opinion, Petitioner has had increased sales since the time of its last rate case, yet is recovering lost revenues. Mr. Rutter argued that the Commission should look at the statutory definition of "revenues lost" in Ind. Code § 8-1-8.5-10(e)(1) and consider whether this term refers to losses that prevented the utility from achieving its base rate-embedded level of sales.

Mr. Rutter claimed that if Petitioner seeks to take advantage of SEA 412 to recover the lost margins and incentive benefits, it should also be required to include the cost benefit analysis the statute requires to justify those benefits. Mr. Rutter further noted that SEA 412 requires the Commission find a DSM Plan reasonable before the utility may be eligible for lost margin and shareholder incentive recovery.

Mr. Rutter argued that while Ms. Douglas briefly discussed residential customer impacts in her direct testimony on page 19, that information alone is not sufficient to provide the Commission the ability to conclude the Plan's effect on short-term and long-term rates. Mr. Rutter claimed that the PCT is an inadequate proxy for the potential effect "on the electric rates and bills of customers that participate in energy efficiency programs" because, like TRC and UCT/PACT, it ignores lost margins and incentives.

Mr. Rutter argued that the OUCC does not support Petitioner's request for recovery of performance incentives, because its programs fail the RIM Test as a portfolio (if excluding demand response programs). Mr. Rutter agrees that 170 IAC 4-8-3 allows for an electric utility to receive shareholder incentives to keep DSM programs on an equal footing with supply-side resources, but he claimed that his Attachment ETR-2 shows that the DSM Plan's avoided cost benefits create an economic incentive for Petitioner to pursue this plan. Mr. Rutter further claimed that it is not reasonable for the Commission to award performance incentives to a utility that sets its own savings targets. For those reasons, he recommended that the Commission deny lost revenues and shareholder incentives and find that the DSM Plan is unreasonable.

7. **CAC's Case-in-Chief.** Ms. Natalie Mims, Principal at Mims Consulting, LLC, provided her expert opinion as to whether or not Petitioner's 2016-2018 energy efficiency plan is reasonable under Ind. Code § 8-1-8.5-10. She recommended that Petitioner's plan should be rejected as unreasonable until all of her recommendations are incorporated into Petitioner's plan. She recommended that while Petitioner works to incorporate her recommendations into its plan, that Petitioner continue to offer its DSM programs as it has under its 2015 plan for purposes of consistency, marketplace certainty, and for the benefit of Petitioner's customers.

She also recommended that Petitioner increase the goals for those programs unaffected by opt-out customers to levels consistent with its Market Potential Action Plan and adding residential new construction, manufactured homes, direct install for schools, and non-residential self-direct programs, and modify its opt-out letter to include details on the benefits of EE. Regarding the Residential New Construction program, she testified that there are many measures that can only be cost-effectively installed during the new construction process, such as building orientation or high efficiency insulation. If Petitioner does not pursue energy efficiency in new residential construction, it will miss cost-effective opportunities for the life of the building, which is referred to as "lost opportunity."

Regarding the manufactured homes program, Ms. Mims recommended that Petitioner implement an upstream efficiency program that is targeted at manufactured home producers, because of the amount of Indiana's housing stock that is comprised of manufactured homes and the use of manufactured homes as affordable housing. She also testified that robust EE programs for low- and fixed-income households are essential to ensuring that all customers are able to afford basic utility service on a sustainable basis, particularly because low-income residents tend to live in less efficient housing. Ms. Mims recommended a program that is similar to a program offered by the Tennessee Valley Authority ("TVA"). In TVA's program, she testified that it pays the manufacturer of the homes to build homes with heat pumps instead of electric resistant heat. When the consumer purchases a new home, she testified that there is no cost differential between the heat pump version and the electric resistant heat version, yet there are tremendous energy savings. Ms. Mims recommended that Petitioner also consider Idaho Power's Rebate Advantage program, where customers that purchase new all-electric ENERGY STAR manufactured homes receive a $1000 sales rebate and sales consultants receive a $200 sales bonus every time they sell a new all-electric ENERGY STAR manufactured home to an Idaho Power customer. Finally, Ms. Mims recommended that Petitioner clarify that its Smart $aver Residential, Residential Energy Assessment, Low-Income Weatherization, Low Income Neighborhood, Agency Assistance Portal, and Appliance Recycling program are available to manufactured home owners and renters. She testified that this may already be the case, but there is no information in the application indicating if a "single family home" is inclusive of a manufactured home.

Regarding the School Audit and Direct Install program, Ms. Mims noted that Duke used to offer this program and recommended that Duke reintroduce it back into its portfolio. She recommended that Duke consider offering incentives on these measures through their commercial prescriptive program to reduce the upfront capital cost for schools to install these measures.

Regarding the C&I self direct program, Ms. Mims recommended that Petitioner offer one that meets the criteria she discussed and requires robust evaluation, measurement and verification. In Cause No. 44310, she testified, a proceeding to investigate a self-direct program, the Commission found that:

> Based on the significant change in the statutory landscape and the resulting impact on the manner in which DSM programs are designed...we find that any further consideration of a structured self-direct DSM program for large customers should occur when an electricity supplier submits its plan for Commission approval.

Ms. Mims testified that energy efficiency is the lowest cost resource, and that Petitioner should look for reasonably achievable ways to attract and retain energy efficiency program participation from their large customers. However, she also testified that it is worth mentioning that without revisions to the net lost revenue recovery, she does not think that any industrial customer will participate in an energy efficiency offering from any utility in Indiana.

Ms. Mims recommended that Petitioner offer more complete information about the available C&I programs to opt out eligible customers, especially when Petitioner sends opt out notification letters and forms, as well as offer more programs specifically catered to these customers to entice them back into participation. Also, she testified, upon review of Petitioner's opt out letter, it appears that Petitioner should modify the language to focus on the benefits the customer is declining when it opts out of efficiency programs. Currently, she testified that the language focuses on the ease with which the customer can opt out of the program. Petitioner should consider adding an additional page with a case study of a successful energy efficiency project likely applicable to the customer as an example of the upside of the energy efficiency programs. Finally, she testified Petitioner should consider additional programs that will entice opt out customers back into participation in the programs, such as a program geared towards the large concentration of steel mills in Petitioner's service territory.

Ms. Mims testified that consistent with CAC testimony in Cause Nos. 44496, 43618 and 43912, if recovery of lost revenues is allowed, it should be limited to the amount associated with decreases in sales that are directly attributable to the implementation of Commission approved EE programs and only to the extent it impacts Petitioner's fixed cost recovery. She testified this would be consistent with Indiana's relevant definitions of "lost revenues" in Ind. Code § 8-1-8.5-10: "the difference, if any, between: revenues lost; and the variable operating and maintenance costs saved; by an electricity supplier as a result of implementing energy efficiency programs." Furthermore, she testified, Ind. Code § 8-1-8.5-10(o) states that if the plan is found to be reasonable under subsection (h), the Commission shall allow "reasonable incentives" and "reasonable lost revenues". She also testified that the current structure of recovery of lost revenues for Petitioner, however, is not reasonable and should be changed to conform to the statute. Finally, she testified that 170 IACEE 4-8-6 already requires consideration of free riders. Petitioner, she testified, should be required to include customer load growth, off-system sales, and changes in other revenue structures when proposing any lost revenue adjustment mechanism. And she testified, changes in these factors between rate cases provide the utility with additional fixed costs recovery, which should be offset in any lost revenue mechanism. Petitioner, she testified, has not provided evidence that it will under recover fixed costs due to the impacts of its EE programs. She testified that this is unreasonable, and is why Indiana's lost revenue adjustment mechanism ("LRAM") is asymmetrical — the utility makes no adjustment for increases in revenues due to activities unassociated with DSM and instead simply assumes that lost revenues due to DSM always occur. Petitioner's LRAM, she testified, would be symmetrical if it took into account its actual revenues before and after the application of its lost revenue. She testified that if increased sales or other factors result in actual revenue plus lost revenues pushing Petitioner past its revenue needs, it should not collect any lost revenue. Petitioner, she testified, could compare sales in its test year to the actual sales, and if there is a difference between that test year and actual year, then Petitioner may be eligible for lost revenues. If the actual sales, she testified, after the effects of EE are included, are still sufficient to allow Petitioner to recover its authorized revenue (for example, when sales are above forecasted levels), there is no legitimate rationale to use ratepayer money to compensate the Petitioner for "lost" revenues that were not incurred. This, she testified, would be essentially asking utility ratepayers to guarantee excess revenues to the utility, and this is not reasonable. However, she testified, if Petitioner's sales, after the effects of EE, are insufficient to allow Petitioner to recover its authorized costs, then Petitioner would be eligible for lost revenues. She testified that lost revenue recovery is meant to be a short-term solution to address revenue loss in between rate cases. She testified that if recovery of lost revenue is allowed, it should be limited to three years or the life of the measure, whichever is shorter, to avoid the "Pancake Effect." Further, she testified that based on ACEEE's recent LRAM research:

> It is most common for states to limit recovery to one to three years, although many states allow utilities to recover lost revenues for an indefinite period of time...Respondents indicated that in these cases, although rules might not be in play...utilities tend to bring [rate cases] forward every two to three years.

In 2012, she testified, that the Commission's order stated, "DEI proposes to collect lost revenue for the shorter of: the first three years of program participation, regardless of whether lost revenues continue to accrue beyond that time, or the life of the measure...Accordingly, we find that DEI should be authorized to recover net lost revenues...as discussed above." She testified, that as noted by the Minnesota Department of Public Service over fifteen years ago, lost revenue recovery is meant to be a short-term adjustment to address revenue losses in between rate cases. She testified Petitioner's witness Goldenberg also acknowledges, "lost revenues are a mechanism to make a utility whole in between rate cases." She recommended that in the absence of requiring a rate case every 2-3 years, the amount of lost revenue the utilities recover should be limited. She testified that it is also important to note that the utility is able, through integrated resource planning and rate cases, to adjust their longer term plans to avoid spending revenue unnecessarily if efficiency can defer or eliminate the need for additional capital expenditures, and thus lost revenues. However, she testified that at this time, Indiana's policy allows the utility to collect revenues that would not be "lost" through prudent planning. In Indiana, she testified, the rationale for 36 months of lost revenue can also be found in SEA 412, which requires the utilities to submit energy efficiency plans at least once every three years. She recommended that lost revenue recovery should be limited to the duration of the energy efficiency plan approved by the Commission under Indiana Code §8-1-8.5-10(h).

Ms. Mims testified that the Commission did not put a time constraint on the methodology, and the Commission's rules state that it may periodically review the need for continued recovery of the lost revenue as a result of the utility's DSM program, and that the approval of a lost revenue recovery mechanism shall not constitute approval of a specific dollar amount, the prudence, or reasonableness of which may be debated in a future proceeding before the Commission. Also, she testified, that the newly enacted Senate Enrolled Act 412, in Section (o), now includes the term "reasonable" in front of the term lost revenues. This is a clear example of the need for a cohesive lost revenue methodology and policy across all utilities in Indiana. Ms. Mims' recommendations for Duke's lost revenue recovery are: (1) the utility show that implementation of energy efficiency programs has prevented the Company from recovery of fixed costs; then (2) use a standard methodology across the State of Indiana to determine how to uniformly calculate lost revenue for a measure and finally, (3) calculate the lost revenue for three years or the life of measure, whichever is shorter.

Ms. Mims testified that given that Petitioner is setting its own energy efficiency goals, she recommends that if the Commission adopts a shared net benefit performance incentive, the Commission require that Petitioner meet 100% of its goal as a threshold for a performance incentive. Nine percent of Petitioner's portfolio program costs are comprised of EM&V, she testified, which is much higher than the industry standard. She recommended that the Commission use multiple criteria to define the performance incentive, and cap the maximum amount of the incentive. She also recommended that during the IRP/EE rulemaking, the Commission and interested stakeholders define the performance criteria based on what is best for Indiana, and determine what the appropriate total incentive cap should be. In the interim, she suggested that the Commission move all of the utilities to a shared net benefit performance incentive that is calculated using the net present value of UCT benefits, and is tiered based on energy savings performance. In other words, she testified, the incentive mechanism could motivate the Company to emphasize investments in low-cost programs that will not serve all customer classes equally. Often, she testified in a typical portfolio, more expensive programs are residential and harder-to-reach sectors such as low-income and small business customers. As these programs are more expensive and have a lower UCT score, she testified, while cost-effective; they are not as lucrative to the utility under the shared net benefit performance incentive. Petitioner, she testified, will be unlikely to maximize its achievement of efficiency without all cost-effective efficiency. She recommends a lower net benefit percentage is more appropriate for Petitioner, particularly as they are using gross savings at the plant to calculate their achievement level. She suggested building on Petitioner's existing structure to create a tiered performance incentive in table 10 of her testimony. She testified that it would be her recommendation that in the absence of: (1) requiring the utility to show that they have "lost" revenues; and (2) shortening the lost revenue recovery period to the shorter of 36 months or the life of the measure, or requiring the utility to return to the Commission for a rate case every three years, Petitioner should not receive a performance incentive. However, she testified, if the lost revenue period is shortened to 36 months or the life of the measure, whichever is shorter, the Commission should allow a performance incentive. She testified Petitioner is proposing to recover performance incentives for at least some of its proposed demand response programs. She testified that this is what demand response programs are. She also testified that language regarding cost recovery in Senate Bill 412 just addresses recovery for energy efficiency programs or programs as defined by Section 10(d). The fact that the legislature made the extra effort to exclude demand response from its definition of program costs, she testified, seems to indicate its rejection of lost revenues and financial incentives for demand response. Thus, she recommended the Commission deny Petitioner's request for performance incentives for any of their demand response programs. She testified performance incentives are part of the SEA 412 IRP/EE rulemaking, Commission RM # 15-06. As part of this effort, she strongly recommended that a workshop be held to discuss a cohesive state policy on performance incentives and calculation of lost revenues, as these areas seem to have the most diverse methodologies among Indiana utilities. In this workshop, she strongly recommended that the Commission and stakeholders consider the costs and benefits of designing a performance incentive that has multiple criteria, as well as identify appropriate criteria for a three-year EE cycle that will motivate the utility to pursue Indiana's EE policy goals.

Ms. Mims testified that Petitioner's proposed evaluation budget is approximately 9.6% of its overall program budget (excluding lost revenues and performance incentives), as shown in Table 13 of her testimony. She testified that this is a high cost for EM&V in her opinion and it is not in compliance with the Indiana Evaluation Framework as filed with the Commission in Cause No. 42693 S-1 on October 9, 2012 by the Demand Side Management Coordination Committee's ("DSMCC") Evaluation Management and Verification Subcommittee which was prepared for the DSMCC by the Indiana Statewide Core Program Evaluation Team (TecMarket Works, the Cadmus Group, Opinion Dynamics Corporation, Integral Analytics, Building Metrics, and Energy Efficient Homes Midwest). She testified that on page 8 of this document under the heading "Targeting the Evaluation Budget at approximately 5% of the Portfolio Budget," it states that "The evaluation cost in Indiana should be set at a level not to exceed approximately 5% of the portfolio budget without approval by the Subcommittee for any given cycle." Further, she testified that it is concerning that Petitioner is including this high EM&V cost in the calculation of its performance incentive. This is unreasonable, she testified and Petitioner should work to reduce its EM&V cost to ~5% of its portfolio. She recommended that in the event that the Commission does not alter Petitioner's performance incentive to be based off of the net benefits of the UCT instead of program costs, the Commission should only allow Petitioner to include EM&V costs of up to 5% of the portfolio cost for the purposes of calculating the performance incentive. She testified that over eighty percent of Petitioner's Core Plus program impacts came from the MyHER and C&I Custom programs, neither of which appear to have any 2014 EM&V data. In fact, she testified that based on the data provided, the only program that has been evaluated for its 2014 savings is the Non-Residential Smart $aver program. Further, she testified that Petitioner anticipates that the MyHER program will achieve 233 of the 421 residential GWh in its 2016-2018 plan, or almost 40 percent of the plan savings. She strongly recommended that, in future filings, Petitioner ensure that programs that contribute to such significant contributions to plan savings have up to date EM&V to ensure that the inputs such as the net-to-gross ratio and realization rate are accurate for planning purposes. In addition, she recommended that Petitioner reduce their EM&V costs to be in line with best practices, at about five percent of the total plan costs.

Mr. Ralph C. Smith, a Senior Regulatory Consultant at Larkin & Associates, PLLC, testified about the requested lost revenues by Petitioner. He provided additional support to CAC witness Natalie Mim's direct testimony ("CAC Exhibit 1") that the Commission deny Duke's 2016–2018 EE plan in this Cause and Petitioner's request for lost revenue.

Mr. Smith testified that Petitioner's base rates were set in 2004 in Cause No. 42359, using a test-year ending in 2002. He further testified that Petitioner has received recovery of additional costs through various trackers without having a base rate case. He pointed out that the prolonged use of trackers without the benefit of a general rate case is unfair to ratepayers in that the utility can raise rates when their costs may have increased without looking at where their costs have decreased.

Mr. Smith also testified that there is no evidence that Petitioner's energy efficiency programs have resulted in net decreases to the retail sales levels that were used in setting its base rates in its last base rate case or that its energy efficiency programs are actually causing Petitioner to fail to receive sufficient revenues to recover its authorized costs. He also testified that ratepayers should not be asked pay extra charges to compensate the utility for lost sales or "lost revenues" when the evidence shows that it has been experiencing retail sales levels that are higher than those used in its last base rate case. He additionally testified that Petitioner has experienced net additional retail sales, rather than sales declines. Thus, he testified, Petitioner's claim for lost revenues in the current proceeding should be rejected.

Mr. Smith testified that lost revenues should not be assumed to exist, and each utility should be required to demonstrate that lost revenues were in fact incurred, which is something that Petitioner has failed to demonstrate in the current proceeding. He further testified that recovery of lost revenues is intended to reimburse a utility for fixed costs that the utility would not be able to recover because the utility's sales that were used to establish its base rates in its last base rate case have been reduced as a result of its energy efficiency programs. However, he testified, Petitioner's conservation actions have not resulted in net retail sales declines compared to the level of sales used to set rates in Petitioner's last base rate case, and thus have not limited Petitioner's reasonable opportunity to recover its fixed costs. He testified that Petitioner should not be allowed to recover lost revenue where the evidence shows as it does here, that since its last base rate case it has experienced net retail sales growth, i.e., it has net additional retail sales, rather than lost sales. Therefore he testified Petitioner's claimed existence of lost revenue is baseless in this case and should be rejected.

Mr. Smith recommended that Petitioner's request for recovery of lost revenues be denied. In the rulemaking proceeding, he recommended that the Commission further examine lost revenue calculations for energy efficiency to ensure that ratepayers statewide participating in investor-owed electric utilities' energy efficiency programs are not being overcharged. Additionally, he testified that he agreed with and endorses CAC Witness Mim's recommendation that if a utility has demonstrated that is has lost revenue, the recovery should be limited to three years or the lie of measure, whichever is shorter.

CAC also moved for administrative notice of the following documents, which was granted by the Commission and admitted into the record: Report of the Indiana Utility Regulatory Commission Electricity Division Director Dr. Bradley K. Borum regarding 2013 Integrated Resource Plans (CAC Administrative Notice Exhibit 1); Cause No. 43955 DSM 2, Petitioner's Exhibit A-2: Duke Energy Indiana's Market Assessment and Action Plan for Electric DSM Programs (CAC Administrative Notice Exhibit 2); Cause No. 42693-S1, 2014 Energizing Indiana Evaluation Report: An Evaluation of the Core Final Year Energy Efficiency Programs, May 1, 2015 (CAC Administrative Notice Exhibit 3); Cause No. 44310 Final Order, May 20, 2015 (CAC Administrative Notice Exhibit 4); Cause No. 43955 Final Order, March 21, 2012 (CAC Administrative Notice Exhibit 5); and Cause No. 42693 S-1, Indiana Evaluation Framework, October 9, 2012 (CAC Administrative Notice Exhibit 6).

8. Petitioner's Rebuttal Testimony. Mr. Timothy Duff, Mr. Goldenberg, Ms. Ham, Ms. Holbrook, and Ms. Douglas, all filed testimony in rebuttal to the testimony of the OUCC and CAC.

Mr. Timothy Duff, General Manager, Market Solutions, Regulatory Strategy & Evaluation, testified in rebuttal to OUCC witness Edward T. Rutter's assertion that the Petitioner should not be entitled to lost margins or a shareholder incentive because the proposed portfolio of programs fail the RIM Test. Mr. Duff testified that Mr. Rutter's claims do not cite any statutory authority in SEA 412 that requires the portfolio of programs to pass the RIM Test, nor does Mr. Rutter's citing to Ind. Code § 8-1-8.5-10(j) and (h) provide any specific language that ties the Commission's approval of lost margins or shareholder incentives to the Petitioner's portfolio of programs passing the RIM Test.

Mr. Duff further testified that he does not believe the RIM Test should be the primary or sole test used in the cost benefit analysis considered by the Commission over the three other standard cost tests (TRC, UCT and PCT) as there is no statutory guidance that would have any undue importance placed on the RIM Test in the Commission's consideration of a utility's EE plan. Mr. Duff stated that the existing rules on Integrated Resource Planning provide that a cost benefit analysis include one or more of the RIM, UCT, TRC or PCT; however, the rules do not state the exclusivity of the RIM Test to determine cost-effectiveness.

Mr. Duff testified that assuming programs are not cost effective to utility customers simply because they fail to pass one of the four accepted tests is illogical. He stated that the calculation methodology under the RIM Test favors programs that provide a high proportion of the total energy savings during the coincident peak as opposed to those that do not, which favors a smaller portfolio of programs that would generate far lower overall energy savings and be inconsistent with the energy savings that have been included in Petitioner's most recently approved IRP. Mr. Duff explained that only three of the eleven residential programs proposed pass the RIM Test and only two of the four proposed non-residential programs pass the RIM Test, which equates to 35% of the total measures proposed passing the RIM Test.

Mr. Duff testified that he does not agree with Mr. Rutter's contention that demand response programs and measures should not be included in EE plans. First, he explained, because the RIM Test clearly favors demand response programs, there's little to no energy savings beyond those associated with the coincident peak savings; to exclude them from what was proposed would reduce the size of the portfolio even more. Second, demand response programs, not targeted at large commercial and industrial customers and not included in Petitioner's Rider 70, have historically been considered and approved along with EE programs as a component of Petitioner's portfolio of DSM programs to be recovered under both Rider 66 and Rider 66A. Mr. Duff testified that, absent the inclusion of these cost effective demand response programs in the Plan and Rider, Petitioner would need another regulatory mechanism through which to administer and fund these demand response programs that have been factored into Petitioner's IRP.

Mr. Duff testified that excluding demand response programs from Petitioner's portfolio is not required by SEA 412. He explained that Ind. Code § 8-1-8.5-10(h) does specify four components that a utility's plan shall include; however, it does not specify a prohibition or restriction from incorporating demand response programs in the filing. Mr. Duff testified that, although Ind. Code § 8-1-8.5-10(d) delineates that EE programs do not include demand response programs, there is no language that would suggest that demand response programs may not be included in a utility's Plan. To the contrary, Ind. Code § 8-1-8.5-10(j)(3)(B) suggests that demand response programs should be included in the plan since the peak demand reductions associated with them have been factored into Petitioner's most recent long range IRP submitted to the Commission. Finally, Mr. Duff stated that to exclude demand response programs would be inconsistent with a market transformation that is being facilitated by technological advances that are blurring the lines between energy efficiency and demand response programs and creating new hybrid programs that are a combination of demand response and energy efficiency.

Mr. Duff also testified that he does not agree with Mr. Rutter's contention that Petitioner should not be awarded performance incentives because it sets its own savings targets. Ind. Code § 8-1-8.5-10 requires an electricity supplier to file on a regular basis with the Commission, a Plan that includes the following: EE goals, the programs proposed to meet those goals, the associated programs budgets, and the EM&V plan to measure and verify the results. Mr. Duff further testified that Mr. Rutter's opposition to both performance incentives and any amount of lost revenues, without any explanation for their change from years past, would appear to be contradictory to SEA 412 and discourage utilities from offering an aggressive portfolio of EE offerings.

In response to CAC witness, Natalie Mims' contention that Petitioner's proposed performance incentive is unreasonable because it is not tied to performance, Mr. Duff testified that Petitioner has proposed a performance incentive that would continue to be tied to the actual energy savings achieved by the Petitioner's administered programs. Petitioner's proposal for 2016 was designed to be simpler and more transparent, but still require the Company to achieve at least 70% of the energy efficiency goals proposed in order to qualify for an incentive.

Mr. Duff further testified that he did not agree with Ms. Mims' contention that Petitioner's proposed performance incentive is unreasonable because it is tied to expenditures. He explained that one of the attributes of a performance incentive structure that is tied to the Petitioner's program expenditures is the transparency and certainty regarding what the incentive will be. Mr. Duff testified that the Company's experience since 2011 has demonstrated that this transparency and certainty around the potential magnitude of the performance incentive has made an incentive tied to earning a return on prudent program expenditures an attractive one.

As to performance incentives on demand response programs included in Petitioner's proposed portfolio of programs, Mr. Duff maintained that Ms. Mims' interpretation of SEA 412 is incorrect. Ms. Mims' attempted to characterize the delineation of demand response from EE in Ind. Code § 8-1-8.5-10(d)(1) to be a restriction to the inclusion of demand response programs from an electric supplier's plan required by Ind. Code § 8-1-8.5-10(h). On the contrary, Ms. Mims does not suggest the removal of demand response programs from the Petitioner's plan, but rather that this delineation only applies to the utility incentive. According to Ind. Code § 8-1-8.5-10(g), it clearly includes EE costs, EM&V costs and "other recoveries." Utility's performance incentives are classified as an "other recovery," as demand response programs are factored into the Petitioner's IRP, and allow Petitioner to avoid other supply side resources. Although it is true that demand response programs are different from EE programs, it is illogical to think that recognizing that difference somehow constitutes a prohibition from including them in the plan or the incentive calculation.

Mr. Duff further testified that he did not agree with CAC witness Mims' contention that the Commission should require Petitioner's financial incentive to include multiple criteria like the Quantifiable Performance Indicators utilized in Vermont, as adding any metric beyond those related to program spending and the energy savings simply adds unnecessary complexity to the process of determining a reasonable financial incentive.

Mr. Goldenberg testified in rebuttal to OUCC witnesses Rutter and Paronish and CAC witness Mims. With respect to OUCC witnesses Rutter and Paronish, Mr. Goldenberg testified that Petitioner does not agree with their contention that its filing should be denied because it did not meet the elements of SEA 412, codified in Ind. Code § 8-1-8.5-10(j). Mr. Goldenberg outlined that Petitioner provided all ten items that the Commission is to consider in approving an EE plan.

Mr. Goldenberg provided citations to testimony where each item in Ind. Code § 8-1-8.5-10(j) could be found. As to projected changes in customer consumption of electricity resulting from the implementation of the plan, Mr. Goldenberg testified that he provided such information in his supplemental testimony (entered into evidence as Petitioner's Exhibit 2) on page 3, where he provided the projected impacts by year.

Mr. Goldenberg testified that Ms. Ham provided the cost benefit analysis information on pages 24 through 28 of her direct testimony (entered into evidence as Petitioner's Exhibit 4). As to consistency with Petitioner's most recently filed IRP, Ind. Code § 8-1-8.5-10(j)(3) and (9), Mr. Goldenberg provided this information in his direct testimony (entered into evidence as Petitioner's Exhibit 1) on pages 13-14, when he explained how Petitioner's proposal was consistent with Petitioner's most recent IRP. Mr. Goldenberg also testified that Petitioner would review its Plan in 2016 after its next IRP submission and provide the information to the Commission on the interaction of the IRP and its Plan in future EE filings. As to the consistency with the State's energy analysis developed by the State Utility Forecasting Group ("SUFG"), Mr. Goldenberg explained that Petitioner's Plan is consistent with the 2013 Forecast, in large part because the SUFG forecast is based on the utilities' IRP Plans.

As to the procedures to be used to conduct EM&V, providing the information necessary for Ind. Code § 8-1-8.5-10(j)(4), Mr. Goldenberg testified that Ms. Ham provided this information in her direct testimony (entered into evidence as Petitioner's Exhibit 4) on pages 3-13..

In regard to the requirements found in Ind. Code § 8-1-8.5-10(j)(5) and (6), Mr. Goldenberg testified that Petitioner provides programs for all customers who are eligible to participate and costs are allocated accordingly.

Mr. Goldenberg further testified that, in regard to Ind. Code § 8-1-8.5-10(j)(7), a comparison of the long term and short term rate impacts on both participants and non-participants, Petitioner provided this information in Ms. Ham's direct testimony (as entered into evidence as Petitioner's Exhibit 4), pages 23-24, by providing both the RIM scores and the PCT scores. Ms. Ham also provided a more detailed explanation of this information in her rebuttal testimony (as entered into evidence as Petitioner's Exhibit 5).

Mr. Goldenberg further testified that he did not agree with OUCC witness Paronish that Petitioner's case-in-chief evidence omits information essential to determining program reasonableness, such as the estimated participants and estimated number of measures to be installed. He testified that Petitioner has provided all data necessary to determine program reasonableness, including cost effectiveness scores, program costs, overheads, EM&V costs, shareholder incentives and lost revenues in its case-in-chief filing and the workpapers of Ms. Holbrook and Ms. Douglas. Furthermore, Mr. Goldenberg testified that the OUCC had not requested the additional information in data requests. With that being said, Mr. Goldenberg provided a supplement to his previously submitted Exhibit A-1 (as entered into evidence as Petitioner's Exhibit 1), which contains a breakdown of each measure by year with the additional detail as requested by the OUCC (see Petitioner's Exhibit G-1, as entered into evidence as Petitioner's Exhibit 3).

In regard to OUCC witness Paronish's claim that Petitioner has not specified how much in total was budgeted for Health and Safety in the Low Income Weatherization Program, Mr.

Goldenberg testified that said health and safety was not a separate program and that Petitioner has provided the necessary data to determine the reasonableness of each program in Ms. Holbrook's Petitioner's Exhibit I-1 (as entered into evidence as Petitioner's Exhibit 8). In further response, he noted that $75,000 per year was budgeted for health and safety mitigation within the overall Low Income Weatherization Program budget. Ms. Paronish also claimed that Petitioner did not provide the details for the refrigerator replacement as part of the Low Income Weatherization Program; however, Petitioner provided such information in response to the OUCC's Data Request Set No. 2, Questions 2.3 through 2.7. Ms. Paronish also claimed that Petitioner has not specified any criteria for determining whether to repair or replace a home's furnace; however, Petitioner provided such information in response to the OUCC's Data Request Set No. 2, Question 2.10, which asked about the level of funding for replacement rather than repair of an existing HVAC system and how any incremental amount over $600 would be funded. Petitioner stated that, should a unit repair exceed the $600 amount, or in the event the system is not worth repairing, a replacement would be considered. The home must be weatherized in order to qualify for a replacement unit and the new HVAC system must be a minimum 15 SEER and 8.2 HSPF. In regard to OUCC witness Paronish's claims that Petitioner failed to provide relevant information, Petitioner would refer the Commission to its 27 page, Exhibit A-1 (as entered into evidence as Petitioner's Exhibit1), detailing each program, its cost components (program costs, overheads, EM&V costs, lost revenues, and shareholder incentives), and cost effectiveness tests. Furthermore, as provided by statute, if the Commission wishes to consider additional items, it may request such information.

Mr. Goldenberg further testified that he did not agree with OUCC witness Paronish that health and safety is not DSM. The two are inextricably linked in Low-Income programs. He testified that Petitioner is following established Department of Energy guidelines (Title 10, Chapter II, Subchapter D, Part 440) involving health and safety issues. Without the ability to help low-income customers with health and safety, Mr. Goldenberg stated that many homes will be bypassed and not have the opportunity to be weatherized unless Petitioner and the Community Action Agencies coordinate the repair of weatherization health and safety improvements up to $750 per home.

In regard to OUCC witness Paronish's claim that Petitioner's appliance recycling program is designed in contradiction to its own program experience, Mr. Goldenberg rebuts this by providing the results of the program. Although the EM&V came back with lower than anticipated impacts for both refrigerators and freezers, customers continue to respond positively to the program, which has proven to be a foundational offering in the residential portfolio.

In regard to OUCC witness Paronish's recommendations that Petitioner take high level minutes of all meetings of the OSB and more OSB oversight of the EM&V vendor and process, Mr. Goldenberg testified that Petitioner is amenable to taking high level minutes of the OSB meetings. As to a more active role in EM&V, Roshena Ham addresses this in her rebuttal testimony (as entered into evidence as Petitioner's Exhibit 5). The OUCC further recommends that the OSB have overspend authority not to exceed 10%; Petitioner is agreeable with this recommendation.

Mr. Goldenberg also testified in response to CAC witness Mims' allegation that Petitioner cannot demonstrate that its EE plan is consistent with its IRP, that it has captured all reasonably achievable EE, or that the Plan would achieve an optimal balance of energy resources. Mr. Goldenberg pointed to his direct testimony (as entered into evidence as Petitioner's Exhibit 1), on page 13, line 20, where he discusses that the Company's next IRP is under development and to be filed in November 2015. As a result, Petitioner used its 2013 IRP as the basis for informing the current EE filing. In the cost-effectiveness analysis undertaken for this filing, the avoided energy and capacity costs were consistent with what was used in the 2013 IRP.

Mr. Goldenberg further pointed out that Petitioner's filed Plan is most consistent with the scenario showing lower spending and impacts that appear in the 2013 IRP. He stated that the filed portfolio is informed by and consistent with Petitioner's current IRP. Furthermore, in Mr. Goldenberg's supplemental testimony (as entered into evidence as Petitioner's Exhibit 2), on page 3, he discusses that it is Petitioner's opinion that the goal set forth in this filing is reasonably achievable as the MWHs in the current filing were exceeded in the 2012-2014 timeframe when Energizing Indiana was in operation and taking into consideration the 80% opt out of eligible load for 2016-2018.

In regard to Ms. Mims' last point regarding the balance of resources, Mr. Goldenberg testified that Petitioner has made a best effort to strike an optimal balance of energy resources in this current filing. Because so much has changed since 2013 when the last IRP was filed, Petitioner has reflected in its portfolio the lower spending and impacts scenario taking into consideration the changes promulgated by SEA 340 and SEA 412, most notably large industrial opt-out and elimination of the Commission goals. As stated in Mr. Goldenberg's direct testimony (as entered into evidence as Petitioner's Exhibit 1), on page 14, starting on line 13, Petitioner will have the opportunity to review how the budget and impacts in this current EE plan portfolio compare and, at that time, present its new IRP analysis. Mr. Goldenberg explained that Petitioner plans to provide information on this to both the OSB and the Commission in future energy efficiency filings.

In regard to CAC witness Mims' assertion that Petitioner should be offering some additional programs, Mr. Goldenberg testified that Petitioner is always willing to consider the addition of other programs as part of its EE portfolio. Furthermore, he stated that Petitioner would commit to working with its OSB to consider the addition of the new construction program, upstream manufactured home program, school audit direct install program, and a self-direct program for potential inclusion in the portfolio in 2017 or after.

In regard to CAC witness Mims' assertion that the efficiency impacts identified in Petitioner's Action Plan are still valid given the change in program administration resulting from SEA 340 and SEA 412, Mr. Goldenberg testified that he does not agree. The MPS was completed in 2013 and released in January 2014. He stated that, during the time the study was developed, the Phase II Order was in effect and there was no opportunity for large commercial and industrial customers to opt out.

Mr. Goldenberg further disagrees with CAC witness Mims' assertion that Petitioner has not taken any action to reduce its opt out rate. In 2014, Petitioner launched its Custom-to-Go suite of calculators intended to assist customers to complete energy savings calculations that meet the program's standards for accuracy. He explained that the suite of easy-to-use tools is applicable to small and medium sized projects and was introduced, in part, to mitigate the decline in participation due to opt-out of larger customers and that there are more calculators planned for release in the later part of 2015.

To further attract larger customers, Mr. Goldenberg testified that Petitioner proposed the addition of 76 new measures to the Smart $aver® Non Residential Prescriptive Program. He stated that with these new measures, Petitioner will now offer 359 measures available to its commercial and industrial customers. Petitioner also offers the Smart $aver® Custom Program, which has no specified list of measures and works with individual customers to enable projects pertaining to their particular needs. Mr. Goldenberg concluded that all of these efforts were made to appeal to commercial and industrial customers and to increase the robustness of its offerings to such customers.

In concluding his rebuttal testimony, Mr. Goldenberg testified that he continues to believe that Petitioner's proposed offering strikes the correct balance between a robust set of EE offers for all customer classes, reasonable rate recovery that reduces the incentive for supply side options over demand side options, and a reasonable rate impact associated with offering the programs.

In rebuttal testimony, Ms. Ham provided updates to the estimated costs for the EM&V for the programs, estimated at $5,031,424 or approximately 4.75% of total costs. The cost by program can be found in her Exhibit I-1 (as entered into evidence as Petitioner's Exhibit 8). These estimated costs changed because, at the time that the EM&V costs for 2016-2018 were compiled earlier in the year, more than half of the projected costs were cost estimates subject to change upon the conclusion of competitive bidding for the EM&V work. She testified that the estimates used were higher due to the uncertainty of pricing and the fact that many of the programs are new programs and the set-up costs for the first EM&V for a new program are typically expected to be above average.

Ms. Ham also provided updates to the estimated timeframe for the EM&V for the programs as recommended by OUCC witness Paronish in her testimony. In Petitioner's Exhibit H-1 (as entered into evidence as Petitioner's Exhibit 5), Ms. Ham updated her previously submitted Exhibit B-2 (as entered into evidence as Petitioner's Exhibit 4), to reflect the scheduled EM&V report for the weatherization program, which is planned to be delivered no later than first quarter of 2018.

Ms. Ham disagreed with Ms. Paronish recommendation that the OSB have greater involvement in the EM&V process, including the selection of an independent vendor. Ms. Ham testified as to how Petitioner's OSB is now involved in the EM&V process. Ms. Ham testified that a member of the Petitioner's Analytics team that coordinates EM&V activities attends monthly OSB meetings when EM&V topics are on the agenda. She explained that at least once a year, an update on the status of all EM&V is provided, in which a summary of the projected activity of the four evaluation firms working on EM&V are presented. Ms. Ham testified that when a draft EM&V report is prepared by an independent evaluator, Petitioner shares the draft report with the OSB. If the independent evaluator revises the draft report, it is provided to the OSB for another review. Ms. Ham stated that once all questions and concerns have been addressed, the evaluation report is considered finalized and submitted for filing.

Ms. Ham explained why Ms. Paronish's recommendation is not feasible, because Petitioner operates EE programs in multiple jurisdictions and employs a competitive bidding process for the EM&V work across all its jurisdictions. Ms. Ham stated that, as a result of the scale of this EM&V work, the Petitioner is able to reduce overall EM&V costs, which benefits all customers. She testified that vendor selections have already been made for EM&V work that is occurring in Indiana, Ohio, Kentucky, North Carolina and South Carolina, through 2018 in many cases, with contracts in place with four independent evaluation consultants for this multi-jurisdictional work. Ms. Ham testified that Petitioner has provided updates to the OSB on the vendor selection progress and there have been no concerns raised or requests by any OSB member, including the OUCC.

Ms. Ham further testified that the OUCC's request for bi-weekly meetings with the EM&V vendors is not reasonable because it would add significant time and cost without adding commensurate value. Ms. Ham suggested more beneficial and efficient ways to share information: (1) quarterly updates; (2) detailed EM&V plans provided to the OSB; and (3) have the evaluator present the summary of the results of the draft report. Petitioner recommends that these suggestions be discussed at a future OSB meeting to determine which recommendations are of value to the OSB and what additional budget would need to be authorized.

Ms. Ham also responded to the OUCC's concerns regarding the methodology used to calculate Petitioner's cost-effectiveness analysis. Although Ms. Ham disagreed with the OUCC's stance that equipment provided to the customer at no cost should be calculated as a cost and not an incentive, Ms. Ham did perform an alternate TRC calculation method as recommended by the OUCC. After adjusting the calculations as recommended, the overall portfolio of programs still would be found to be cost-effective under the TRC Test.

However, Petitioner disagreed with the OUCC's recommended change and Ms. Ham testified that Petitioner calculated the TRC Test consistent with how it has calculated it in the past for Petitioner's filings under IURC Cause No. 43955, since 2010. Furthermore, Ms. Ham stated that the current version of the California SPM was written in 2001 and does not define incentive, which left the definition of incentive open to interpretation by those entities that refer to the SPM. Ms. Ham testified that Commission rules do not state that the Petitioner is to follow the California protocols; Petitioner has not viewed it as appropriate to revise the definition of incentives.

Ms. Ham further testified that she does not agree with OUCC witness Paronish's statement that Petitioner is using TRC scores to support its claim that its proposed DSM programs are cost effective and reasonable. Petitioner does not claim that passing the TRC score is a requirement for programs to be considered cost effective and reasonable. Ms. Ham pointed out that OUCC witness Rutter's testimony states that Petitioner is using the UCT/PCT Test to demonstrate that its programs are cost effective and reasonable. Ms. Ham testified that Petitioner reviews the results of all four of the cost-effectiveness tests to arrive at the conclusion that the individual programs, and the combined portfolio of programs, are reasonable. Ms. Ham also testified that the fact that the Low Income Weatherization program does not pass the TRC Test using the method proposed by the OUCC does not change any of the financial conclusions in Petitioner's filing.

Ms. Ham also testified as to OUCC witness Rutter's claim that Petitioner did not present complete results for the PCT. Ms. Ham testified that in her direct testimony (as entered into evidence as Petitioner's Exhibit 4), there is a footnote attached to the table listed on pages 23-24, stating that the PCT was presented for all programs; however, because it is mathematically impossible to calculate a score for a program that requires no participant costs to participate in the DSM program (would require division by zero), Petitioner did not include a value for those programs where no participant costs existed. This has been further clarified in the tables provided in Ms. Ham's rebuttal testimony (as entered into evidence as Petitioner's Exhibit 5) by placing a ">1.00" in the tables for those programs where it is mathematically impossible to calculate a PCT score. Because these programs do not include any participant costs, they have a PCT score of >1.00 and they obviously pass the test.

Ms. Ham also testified as to OUCC witness Rutter's allegation that Petitioner's DSM Plan did not pass the UCT/PCT, RIM and TRC Tests. Ms. Ham testified that Petitioner has updated the portion of the program costs that were expected for EM&V. With this revision, the portfolio of efficiency programs does indeed pass all four tests. Ms. Ham testified that all programs, with the exception of one low income program, pass the TRC and UCT on an individual basis.

Ms. Ham also testified as to OUCC witness Rutter's claim that Petitioner failed to meet the requirements of Ind. Code § 8-1-8.5-10(j)(7), providing information about the short-term and long-term impacts on participants and non-participants. Ms. Ham testified that PCT was calculated for all programs; however, it was only reportable for those programs where the customer had out-of-pocket costs. Because all of the programs proposed by Petitioner have a PCT greater than 1.0, it has proven that these programs will have a positive impact on customer bills for customers that participate in the programs.

Ms. Ham further testified that RIM Tests should not be modified to factor in shareholder incentives as suggested by OUCC witness Rutter, as the RIM Test is not designed to include the addition of shareholder incentives. In fact, Mr. Rutter correctly states as much in his testimony (as entered into evidence as Public Exhibit 2) on page 8, where he explains the RIM Test and states the RIM Test does not include shareholder incentives.

Ms. Holbrook testified in rebuttal to OUCC witness Rutter's testimony and CAC witness Mims' testimony, along with providing an update to the EM&V costs projected for 2016-2018. Ms. Holbrook updated the estimated EM&V costs that were included in Petitioner's original estimate, previously submitted as Petitioner's Exhibit C-5 (as entered into evidence as Petitioner's Exhibit 7), updated now as and reflected in Petitioner's Exhibit I-1 (as entered into evidence as Petitioner's Exhibit 8).

Ms. Holbrook testified that Petitioner disagrees with OUCC witness Rutter's calculation of the revenue requirement per kWh presented on page 11 of his testimony (as entered into evidence as Public Exhibit 2), where he quotes an average $0.35/kWh for the cost of the 2016–2018 programs, inclusive of incentives and lost revenues. He confuses the issue by including persisting lost revenues from previous program years and portfolios and then dividing the total amount by the program kWh savings proposed to be achieved in the 2016–2018 timeline under the portfolio in this current filing. Because the numerator contains total lost revenues from all programs offered to date, but the denominator includes only kWh to be achieved for the 2016–2018 programs, they are not properly aligned and Mr. Rutter's analysis significantly overstates the cost per kWh. If a calculation of cost per kWh inclusive of program costs, incentives, and lost revenues is to be meaningful, it would be more appropriate to look at the calculation on a cumulative basis including lost revenues, incentives, and program costs from 2012 through 2018 (including an estimate for 2015). Doing so would result in a figure of approximately $0.24/kWh on average for the 2016–2018 time period.

Ms. Douglas testified in rebuttal regarding the reason for revising the proposed rates previously sponsored in Exhibit D (as entered into evidence as Exhibit 9). She testified that Ms. Ham revised the forecast for EM&V expenses expected to be incurred in 2016 and Ms. Holbrook revised the 2016 EM&V costs and 2016 performance incentive amounts. Ms. Douglas stated that due to the revised forecast, Residential costs decreased from the amount included in the original plan by $1,101,889 in EM&V costs and $111,195 in performance incentives. Non-residential costs decreased from the amount included in the original plan by $337,130 in EM&V costs and $40,455 in performance incentives. Ms. Douglas further testified that no other substantive changes were made other than reflecting the forecast revision. She did make one rounding correction on page 8 of Petitioner's Exhibit D-2 (as entered into evidence as Petitioner's Exhibit 9), now revised and submitted as Petitioner's Exhibit J-2 (as entered into evidence as Petitioner's Exhibit 10). Although not all pages of Ms. Douglas' original exhibits were revised (Petitioner's Exhibits D-1, D-2, and D-3, and as entered into evidence as Petitioner's Exhibit 9), she provided complete revised exhibits reflecting the forecast revisions as Petitioner's Exhibits J-1, J-2, and J-3 (as entered into evidence as Petitioner's Exhibit 10). Ms. Douglas also filed a revised Workpaper 10 that was revised to reflect the forecast changes.

Ms. Douglas testified that Petitioner was proposing to update its Standard Contract Rider No. 66-A, Fifth Revised Sheet No. 66-A (Petitioner's Exhibit J-1, as entered into evidence as Petitioner's Exhibit 10), subject to Petitioner's filing of the updated Rider 66-A Tariff Sheet with the Commission's Electricity Division, and to begin billing the 2016 rates effective with the later of the first billing cycle of January 2016 or for all bills rendered on or after the effective date of the Commission's Order in this proceeding.

Ms. Douglas testified that she did not agree with the OUCC and CAC's opposition to Petitioner's recovery of lost revenues, because the recovery of lost revenues is intended to reimburse Petitioner for fixed costs that will otherwise not be recovered because of the reduction in sales associated with its EE offerings. Furthermore, Petitioner's 2012-2015 EE program lost revenues have previously been approved for recovery by the Commission in Cause Nos. 43955, 43079 DSM-6, 43955 DSM-1 and 43955 DSM-2. Ms. Douglas also explained why lost revenues are a real cost of energy efficiency. Petitioner's historical ratemaking model establishes base rates by dividing revenue requirements by volumetric sales and number of customers. The revenue requirements include variable, fixed and customer costs. For every unit of energy not sold because of a DSM measure, the fixed and variable costs that unit of revenue would have recovered is foregone. Ms. Douglas testified that a utility does not incur variable costs on a unit of energy that is not sold, because those costs are only incurred for energy produced or purchased. In contrast, fixed costs, such as the cost of the physical generation assets in which the utility has invested on behalf of the utility's electric customers or the majority of the salaries of the Company employees staffing the power plants, do not vary with energy production and are incurred regardless of the level of energy usage. Therefore, every lost unit of energy resulting from successful DSM programs results in the utility not receiving the revenue that it would have otherwise received to reimburse it for fixed costs.

Ms. Douglas testified that lost revenues are a concern in the context of DSM programs as they are designed specifically to reduce energy sales, which in turn, reduces the revenues that can cover a utility's fixed costs. She explained that this creates a disincentive for electric utilities to promote DSM programs, or if the utility does promote DSM programs, it creates a loss of revenue needed to cover fixed costs previously incurred on behalf of customers. Recovery of these lost revenues is an important mechanism to reduce this disincentive and provide for recovery of fixed costs. Ms. Douglas further testified that the Commission's rules allow for the recovery of lost revenues to enable a utility to recover the fixed costs that might otherwise be unrecovered when EE programs reduce energy sales, citing Commission rules 170 IAC 4-8-3(a) and 170 IAC 4-8-5 through 170 IAC 4-8-7.

Ms. Douglas testified that if the Commission approves Petitioner's 2016-2018 programs, it will incur lost revenues associated with its EE programs, because customer revenues intended to cover fixed costs will be less than would otherwise have been the case. Ms. Douglas further testified that the lost revenue impacts from Petitioner's 2016-2018 programs will persist for the duration of the life of each individual measure, which is different measure by measure, or until the energy savings reductions are reflected in the level of sales used to set new base retail rates in a base rate case.

Ms. Douglas further testified that if the Commission accepts Ms. Mims' recommendation that lost revenue recovery be limited to a three-year life rather than the life of the measure, it does not mean that Petitioner will not incur lost revenue after the three years. Petitioner will continue to incur lost revenues until the end of the measure life, unless there is an intervening base rate case to reset rates using the now-lower level of sales.

Ms. Douglas testified that Petitioner would incur lost revenues in 2016 through 2018 associated with its 2012 through 2015 EE programs. Again, absent the recovery of lost revenues, customer revenues intended to cover fixed costs will be less than would otherwise have been the case and shareholders will be negatively impacted until such time fixed costs are reallocated to all customers using sales levels that reflect the reductions that resulted from the EE programs in a future retail rate case.

In regard to Mr. Rutter and Mr. Smith's contention that Petitioner's request for lost revenues should be denied in part because retail sales have increased since its last rate case, Ms. Douglas testified that Mr. Rutter made his recommendation after comparing sales for only a few select customer classes for which lost revenues were included, which does not show the entire retail sales picture and Mr. Smith did a similar analysis using only the same subset of customer classes. She stated that neither the OUCC nor the CAC have taken exception with the energy savings numbers used to calculate the proposed lost revenues or denied that energy usage reductions will result from the Petitioner's 2012 through 2015 programs or the programs proposed for 2016-2018. Because Petitioner's revenues are billed based on energy usage, any reduction in energy usage due to the success of its EE programs will cause a reduction in Petitioner's revenues from what they otherwise would be absent the EE programs. Recovery of lost revenues provides the Petitioner with the opportunity to cover its fixed costs and an opportunity to earn its authorized return.

Ms. Douglas further testified that she also has concerns with Mr. Smith's proposal as under it, even a minor 1,000 increase in kWh would result in Petitioner not being allowed to recover lost revenues that could be significantly larger than the revenue impact of the noted sales increase. Furthermore, Ms. Douglas explained that just because total retail sales increase does not mean that fixed cost recovery has increased. Ms. Douglas also testified that she did not agree with Mr. Rutter's contention that if sales exceed the amount included in base rates, that Petitioner would realize a boost to the authorized allowable rate of return. She explained that Mr. Rutter incorrectly assumes that when a utility's sales increase over time, there are no corresponding increases in fixed costs. To the contrary, both variable and fixed costs normally increase over time as customers are added and more power is delivered, requiring more distribution and transmission investment and related operation and maintenance expense, among other costs. In addition, Ms. Douglas testified that over time, the amount of labor and material costs included as fixed costs normally increase with inflation. Between rate cases, a utility's revenues from increased sales are used to help recover these incremental cost increases, both fixed and variable. Both the incremental revenues from increased sales and recovery of the lost revenues resulting from the utility's EE programs, which were intended to cover the original level of fixed costs embedded in base rates, are necessary to enable the utility to continue to have the opportunity to earn its authorized return.

Ms. Douglas testified that Mr. Rutter's analysis showing the implementation of the company's proposed 2016-2018 Plan as causing Petitioner's overall rate of return and return on common equity to surpass its authorized levels, is theoretically unsound. First, she explained, Mr. Rutter adjusts the level of earnings (operating income) authorized in the last base rate case, which by default, will result in a higher rate of return rather than incorporating the impact of the proposed EE plan into a current level of the Petitioner's earnings before comparing to an authorized level. Second, the UCT/PCT net benefit Mr. Rutter used in his calculation is a net present value of expected avoided cost benefits to be obtained over the lives of all the measures included in the portfolio, net of program costs to be incurred. While appropriate for evaluating the cost effectiveness of the proposed programs, it is inappropriate to be used in a return analysis in the way Mr. Rutter used it. Mr. Rutter's analysis incorrectly assumed that the benefits of avoiding future costs (costs which have not yet been incurred and are not ongoing costs which are in the authorized earnings level, such as for additional T&D capital investment or incremental production plant investment) will increase Petitioner's earnings. In fact, if such future capital investments were able to be made rather than avoided, future revenues would be higher because Petitioner would earn a return on the investments. Thirdly, Mr. Rutter incorrectly adds lost revenues to the authorized earnings level, without reflecting the reduction in earnings that will occur due to the reduction in sales giving rise to the lost revenues. Lost revenues by their nature replace revenues that are lost due to the EE programs.

Ms. Douglas further testified that the performance incentive, net of applicable income taxes, is the only portion of the Petitioner's proposed request that does impact Petitioner's earnings. However, Ind. Code § 8-1-8.5-10(o) allows for such reasonable incentives and the Commission has previously recognized that performance incentives are necessary to keep demand-side resources on a level playing field with supply-side resources. Furthermore, granting of a performance incentive to incent a utility to offer EE programs rather than add supply-side resources does not mean that utility will exceed its authorized return.

Ms. Douglas testified that there is an alternative calculation to Mr. Rutter's analysis to demonstrate that the lost revenues and performance incentives proposed are reasonable. Ind. Code § 8-1-2-42(d)(3) compares jurisdictional authorized earnings with actual earnings and authorized return with earned rate of return ("FAC Earnings Test"), which would reflect the impact of any changes in sales (both from customer growth and from reductions realized from successful EE programs), revenues (including amounts recovered in the EE Rider for lost revenues and incentives or from other riders), and expenditures levels. This comparison is done quarterly with the fuel clause filing and is reviewed as part of the quarterly audit performed by the OUCC. In the Commission's most recent FAC Order in Cause No. 38707 FAC 104 issued June 24, 2015, the Commission found that Petitioner did not earn a return in excess of its authorized level during the twelve months ended February 28, 2015. Furthermore, the testimony filed with Cause No. 38707 FAC 105 (currently pending) similarly shows that Petitioner did not earn a return in excess of its authorized level during the twelve months ended May 31, 2015. This test is more instructive and presents a better picture of the impacts on Petitioner's earnings and return of approving Petitioner's request for lost revenues and incentives than do Mr. Rutter's flawed calculations.

Ms. Douglas provided the Commission with Petitioner's Exhibit J-4 (as entered into evidence as Petitioner's Exhibit 10), a calculation of the estimated difference in revenues (from both lost revenues and performance incentives) between what was included in the revenue amounts recorded during the twelve months ended February 28, 2015, the period used in the FAC 104 earnings test, and what has been proposed for recovery in 2016-2018 in this proceeding. This Exhibit shows that Petitioner's proposed 2016 lost revenue and performance incentive recovery would result in approximately $10.4 million more revenues than what it received for lost revenues and performance incentives during the twelve months ended February 28, 2015, $12.3 million more than the referenced base period in 2017, and $9.8 million more than the base period in 2018.

Ms. Douglas also provided the Commission with Petitioner's Exhibit J-5 (as entered into evidence as Petitioner's Exhibit 10). It adds the amounts of additional revenues, less estimated income taxes at the 39.144% 2016 composite (state and federal) income tax rate, to the electric operating income (return) level approved by the Commission in FAC 104, to determine what impact approving Petitioner's request in this proceeding would have on its electric operating income as compared to its authorized level of return. As row 15 on page 1 of Petitioner's Exhibit J-5 (as entered into evidence as Petitioner's Exhibit 10) shows, the adjusted electric operating income level would still be well under the authorized level referenced by the Commission. It also shows that whether you consider original-cost rate base, fair value rate base, or the phasing-in of the impacts of additional plant being recovered through Riders, the rate of return is less than that approved in base rates in Cause No. 42359, 6.20% compared to the 7.30% cost of capital approved by the Commission or 5.26% compared to the 5.51% fair value return referenced by Mr. Rutter. The analyses for 2017 and 2018 on pages 2 and 3 of Petitioner's Exhibit J-5 (as entered into evidence as Petitioner's Exhibit 10) show similar results. Therefore, there is no reason to expect that recovery of the proposed lost revenues or performance incentives requested in this proceeding will cause Petitioner to exceed its authorized return.

Ms. Douglas testified that she did not agree with Mr. Rutter's assertion that Petitioner's recovery of performance incentives equal to 12% of program costs is unreasonable compared to Petitioner's return on a supply-side option such as a new plant. Ms. Douglas testified that Mr. Rutter failed to recognize that the 12% performance incentive rate is a before-tax rate and that of the 12%, approximately 4.7% will go towards income leaving approximately 7.3% of after-tax return. Mr. Rutter also misstated that Petitioner would earn a return on its investment of 5.51% if it chose to meet demand with a supply-side option such as a new plant; however, the 5.51% he quotes is the rate of return on fair value rate base approved by the Commission in Cause No. 42359, not the weighted cost of capital approved by the Commission in the same case, reflecting a 10.5% cost of equity, which was applied to original cost depreciated rate base to develop revenue requirements – that rate is 7.30% on an after-tax basis, as shown in Petitioner's Exhibit J-6 (as entered into evidence as Petitioner's Exhibit 10). It is this original cost view of cost of capital that is applied to original cost depreciated rate base to determine the amount of revenue requirements included in rate cases and capital recovery riders for supply-side options and is the more appropriate rate to be applied when comparing to the rate used to develop the performance incentive revenues to be recovered under this EE Rider. In Ms. Douglas's opinion, the 7.3% after-tax rate (12% before tax) Petitioner has proposed for incentives in this proceeding is reasonable.

Ms. Douglas further testified that she disagreed with Mr. Rutter's assertion that Petitioner's recovery of incentives were unreasonable as compared to its allowed return. Ms. Douglas testified that Mr. Rutter used the same flawed calculations from his ETR Attachment 2, to support his contention that was previously addressed related to Lost Revenues. As Ms. Douglas' Exhibits J-4 and J-5 (as entered into evidence as Petitioner's Exhibit 10) show, the impact of the increased level of incentives and lost revenues proposed for recovery in 2016–2018 will not cause Petitioner to earn more than its allowed fair value return or more than its authorized earnings amount.

In conclusion, Ms. Douglas testified that Indiana Administrative Code and SEA 340 provide that the Commission can approve lost revenues and performance incentives. Furthermore, SEA 412 provides that, if the Commission finds a plan submitted by an electricity supplier to be reasonable, the Commission shall allow the electricity supplier to recover reasonable financial incentives and reasonable lost revenues. It has been recognized by this Commission that lost revenues and incentives are a necessary component to remove a disincentive or penalty for utilities to offer EE programs. The Commission has previously approved rates for Petitioner that include lost revenues and performance incentives. It is undisputed that lower sales result from successful EE programs and that Petitioner's 2012, 2013, and 2014 programs produced kWh savings resulting in lower sales than would otherwise have been the case. No party has disputed that Petitioner's 2015 and proposed 2016 EE programs will also produce kWh savings resulting in lower sales. Absent lost revenue recovery, the lower sales will cause Petitioner to receive a lower level of revenue intended to cover its fixed costs, causing negative impacts on its ability to earn its authorized return. This reduction in revenues will continue for the life of the measure or until the next base rate case. As shown in Petitioner's Exhibits J-4 and J-5 (as entered into evidence as Petitioner's Exhibit 10), the level of lost revenues and incentives requested for 2016 is reasonable when considering the impact on actual earnings (return) compared to authorized levels. As shown in Petitioner's Exhibit J-7 (as entered into evidence as Petitioner's Exhibit 10), the incentive rate on EE program expenditures proposed by Petitioner is reasonable as compared to the return on a supply-side option. The lost revenues and incentives that Petitioner has included in its proposed rates in this proceeding reflect EM&V results received prior to the filing and will continue to be trued up to EM&V results received to ensure customers are not being overcharged, are consistent with the establishment of just and reasonable rates, and should be approved for recovery by the Commission. Additionally, no party has disputed that Petitioner's rate calculations or calculation of lost revenues or incentives were flawed.

9. <u>Commission Discussion and Findings</u>. Petitioner requests approval of its Demand Side Management and Energy Efficiency programs for 2016-2018 and authority to recover program costs, lost revenues, and shareholder incentives associated with the Energy Efficiency Programs through its DSMA Mechanism in accordance with Sections 9 and 10 and the DSM Rules.

As indicated earlier, Ind. Code ch. 8-1-8.5 establishes a least-cost standard for issuances of certificates of public convenience and necessity prior to construction of new generation facilities. Both the DSM and IRP Rules were adopted to assist the Commission in implementing Ind. Code ch. 8-1-8.5. The IRP Rules require utilities to consider on a biennial basis both supply- and demand-side resources to meet their long-term resource needs in a least-cost manner. The consideration of a utility's resource needs is performed through a long-range planning analysis, i.e., the IRP. Because of the often inherent regulatory or financial bias against demand-side resources, the DSM Rules were adopted to allow the Commission the opportunity to review any bias against DSM and establish guidelines for doing so. The DSM Rules address cost recovery related to all demand-side management activities, including the subset of energy efficiency improvements.[2] Consequently, the Commission has historically considered and approved utility DSM programs and associated cost recovery under Ind. Code ch. 8-1-8.5 and its DSM Rules. *See e.g., Indianapolis Power & Light*, Cause No. 43623 (IURC 2/10/10) and *Indiana Michigan Power Co.*, Cause No. 44486 (IURC 12/3/14).

In 2015, the Indiana Legislature enacted Section 10 establishing that,

> [b]eginning not later than calendar year 2017, and not less than one (1) time every three (3) years, an electricity supplier shall petition the commission for approval of a plan that includes:
>
> (1) energy efficiency goals;
> (2) energy efficiency programs to achieve the energy efficiency goals;
> (3) program budgets and program costs; and
> (4) evaluation, measurement, and verification procedures that must include independent evaluation, measurement, and verification.

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[2] Energy efficiency improvements have been traditionally limited to activities that reduce energy use for a comparable level of energy service. *See* 170 IAC 4-8-1(j) and Ind. Code § 8-1-8.5-9(c) and -10(b). Whereas, a demand-side resource is broader and encompasses any activity that reduces the demand for electric service, e.g., air conditioning load management, time-of-use, and demand response programs.

Ind. Code § 8-1-8.5-10(h).[3] Once such a plan has been submitted, the Commission is required to consider the ten factors enumerated in Section 10(j) to determine the overall reasonableness of the proposed plan. After making its determination of overall reasonableness, Sections 10(k), (l), and (m) establish three possible actions the Commission may take concerning the proposed plan.

Consequently, beginning not later than calendar year 2017, electricity suppliers are statutorily required to submit an energy efficiency plan to the Commission for approval. Until that time, an electricity supplier, when seeking approval of proposed energy efficiency programs and associated cost recovery, may elect to file under Section 10 or under Section 9 and the DSM Rules. We reach this conclusion for several reasons.

The first step in statutory construction is to determine if the statute is clear and unambiguous. If a statute is clear and unambiguous, there is no room for judicial construction. *Thatcher v. City of Kokomo*, 962 N.E.2d 1224 (Ind. 2012). In addition, when interpreting the words of a single section of a statute, a court must construe them with due regard for all other sections and with regard to the legislative intent to carry out the spirit and purpose of the act. *N.D.F. v. State*, 775 N.E.2d 1085 (Ind. 2002).

Although Section 10 is less than clear regarding whether an electricity supplier has until January 1, 2017 or until December 31, 2017 to file a petition for approval of an energy efficiency plan, it is clear that such an obligation does not apply until at least 2017.[4] When enacting Section 10, the Legislature could have required electricity suppliers to submit a plan by the effective date of the statute, a date certain (including one before 2017), or upon expiration of a utility's current DSM program authorization, but it did not. Instead, the Legislature determined that electricity suppliers should have until calendar year 2017 to file their energy efficiency plans. The fact that Section 10, under Ind. Code § 8-1-8.5-10(h) and (q) respectively, establishes specific requirements for the content of the plans and instructs the Commission to adopt rules or guidelines for the implementation of that section, also supports our conclusion that electricity suppliers have until calendar year 2017 to submit a plan for Commission approval.

When the Legislature enacts a particular piece of legislation, it is presumed to be aware of existing statutes on the same subject. *Lake Co. Bd. Of Elections and Registration v. Millender,* 727 N.E.2d 483 (Ind. Ct. App. 2000). Consequently, when the Legislature enacted Section 10, it was also aware of an electricity supplier's general obligation to consider both demand- and supply-side resources in meeting the future electric service needs of its customers through its IRP as well as the provisions of Section 9(m). Section 9(m) provides that after December 31, 2014, an electricity supplier may offer a cost-effective portfolio of energy efficiency programs and submit its proposal to the Commission for review. If the Commission finds the proposal reasonable and cost-effective, the electricity supplier may recover associated costs in the same manner as they were recovered under the Phase II Order, i.e., as authorized under the DSM Rules. *See* Phase II Order at 49. After 2017, Section 10 imposes a specific and mandatory requirement regarding

[3] Section 10(f) also defines a "plan" for purposes of this section as the four requirements set forth in Section 10(h).
[4] Because a calendar year encompasses an entire 12-month period, it is unclear whether "beginning not later than calendar year 2017" means the utility has until the beginning of calendar year 2017 (i.e., January 1, 2017) or until the end of calendar year 2017 (i.e., December 31, 2017) to file a plan. However, we need not make that determination here.

energy efficiency offerings, whereas none of the other provisions of Ind. Code ch. 8-1-8.5, including Section 9, or the DSM Rules impose such requirements. In addition, Section 10 authorizes recovery of reasonable financial incentives and lost revenues if an electricity supplier's plan is approved, unlike under Section 9(m) and the DSM rules where such recovery is discretionary with the Commission.

Although Sections 10 and 9(m) may appear to conflict, at least after 2017, statutes covering the same subject matter should be construed in a way that produces a harmonious statutory scheme. *In re ITT Derivative Litigation*, 932 N.E.2d 664 (Ind. 2010). Courts will strive to avoid a construction that renders any part of the statute meaningless or superfluous. *Hizer v. Holt*, 937 N.E.2d 1 (Ind. App. 2010). But, in the case of a conflict, a more specific provision prevails over a more general provision. *State v. Greenwood*, 665 N.E.2d 579 (Ind. 1996). When examining these two sections together, they can be read harmoniously and in a way that gives meaning to Section 9(m) until at least 2017. Allowing an electricity supplier to seek approval of its energy efficiency programs under Section 9(m) until it is obligated to do so under Section 10 provides the utilities with the opportunity and ability to continue offering cost-effective energy efficiency programs when its existing programs expire while it prepares to meet the specific criteria established in Section 10. We recognize that some utilities may be ready to meet the Section 10 requirements sooner than others. In addition, while the Commission is currently in the process of developing a rule that will address Section 10 requirements, it has yet to issue any final rules or guidance. Therefore, we find it is appropriate for electricity suppliers to file and for us to approve energy efficiency plans under Section 9(m) and the DSM Rule until such time as the electricity supplier submits an energy efficiency plan that meets the requirements of Section 10.

We would also note that, although Sections 10 and 9(m) may conflict after 2017 as both sections address an electricity supplier's energy efficiency plans, neither section addresses a utility's offering of a demand-side measure that is not energy efficiency. Nor did the addition of Section 10, or any of the amendments to other provisions in Ind. Code ch. 8-1-8.5, alter or otherwise abrogate an electricity supplier's obligation to consider both demand- and supply-side resources in meeting the future electric service needs of its customers. Instead, the 2015 amendments to Ind. Code ch. 8-1-8.5, if anything, only strengthened a utility's obligation to consider DSM in its IRP. *See* Ind. Code § 8-1-8.5-3(e). Therefore, we fully expect that electricity suppliers will continue to seek Commission approval under the general provisions of Ind. Code ch. 8-1-8.5 and the DSM Rules when requesting associated cost recovery for DSM programs that do not qualify as energy efficiency under either Sections 9 or 10.

Given this legal background, we begin by considering Petitioner's request for approval of its Energy Efficiency plan under Section 10.

A. Section 10 – Presentation of a Plan. The evidence is uncontroverted that Petitioner is an electricity supplier as defined by Section 10(a) and that it has made a submission under Section 10(h) seeking approval of a proposed plan prior to 2017. However, the evidence is disputed as to whether Petitioner has submitted a plan that includes all four of the criteria required by Section 10(c), i.e., goals, programs to achieve goals, budgets and program costs, and independent EM&V.

Section 10(c) specifically defines "energy efficiency goals" as,

> [a]ll energy efficiency produced by cost effective plans that are:
> (1) reasonably achievable;
> (2) consistent with an electricity supplier's integrated resource plan; and
> (3) designed to achieve an optimal balance of energy resources in an electricity supplier's service territory.

Petitioner asserts that its EE plan is reasonably achievable and consistent with the Company's most recent IRP. Mr. Goldenberg testified that the Company used its 2013 IRP as the basis for informing the current energy efficiency filing.

The CAC disagrees that Petitioner has satisfied the requirements in Section 10(c). Specifically, the CAC argues that the Company's EE plan is not consistent with the Company's 2013 IRP nor that the plan submitted is designed to achieve an optimal balance of energy resources. CAC quoted a Company response to a data request which stated in part that "the 2013 IRP relied on a set of assumptions that are no longer valid given subsequent legislative activity."

Based on the evidence presented, we agree that Petitioner's EE goals and plan are not consistent with the Company's 2013 IRP, nor can they be, because of the very large policy changes implemented as a result of SEA 340 and SEA 412 since the IRP was developed. At best, Petitioner can claim that the avoided costs for energy and capacity used to develop the current EE plan are consistent with the avoided costs used in the 2013 IRP. However, use of the word "consistent" should not be read to say the two sets of avoided costs are necessarily equal or the same. Also, Petitioner argues the EE goals and plan were informed by the 2013 IRP but does not say how. Clearly, the 2013 IRP was developed in a very different policy environment, so it is not understandable how that IRP informed the current proposal.

The law does not define what is meant by an optimal balance nor does the law specify things the Commission should consider when making a determination. However, it stands to reason that an optimal balance can only result from a well-developed and reasoned IRP that evaluates the appropriate balance of new supply-side and demand-side resources taking account of risks and uncertainty. Petitioner's EE goals and plan are not based on an IRP as Petitioner acknowledges, instead the goals and EE plan were "informed" by the 2013 IRP. Petitioner's 2013 IRP developed three scenarios used to evaluate resource requirements and choices. However, in each scenario Petitioner assumed a given level of EE and then allowed the model to optimize the generation resource selection. In the 2013 IRP report Petitioner even explicitly refers to the "assumed" levels of EE. Thus the 2013 IRP cannot be said to have developed an optimal balance of energy resources.

Because Petitioner has failed to provide energy efficiency goals consistent with Section 10(c) which is the first required element of a plan, we find that Petitioner has failed to submit a plan as required by Section 10(h). Accordingly, Petitioner remains under the statutory obligation to file, beginning no later than calendar year 2017, a plan that satisfies the criteria of Section 10(h).

B. Section 9 and the DSM Rules – Energy Efficiency Programs. As set forth above, the Commission has the authority, at least until 2017, to regulate an electricity supplier's offering of energy efficiency programs under the general provisions of Ind. Code ch. 8-1-8.5, Section 9(m), and its DSM Rules. Accordingly, we consider Petitioner's proposed programs and request for associated cost recovery under that authority.

1. Petitioner's EE Portfolio and EM&V Processes. Petitioner's proposal includes sixteen programs for all participating market sectors. The programs are as follows: (1) Agency Assistance Portal; (2) Appliance Recycling Program; (3) Energy Efficiency Education Program for Schools; (4) Low Income Neighborhood; (5) Low Income Weatherization; (6) Multi-Family EE Products and Services; (7) My Home Energy Report; (8) Residential Energy Assessments; (9) Smart $aver Residential; (10) Power Manager; (11) Power Manager for Apartments; (12) Power Manager for Business; (13) Small Business Energy Saver; (14) Smart $aver Non-residential Custom Incentive; and (15) Smart $aver Non-Residential Prescriptive Incentive.

The Company presents cost-effectiveness results for each program and all programs combined for the UCT, TRC, RIM, and PCT. Only one program failed the UCT – the Low Income Weatherization Program. No programs failed the TRC and five programs passed the RIM test. The full portfolio passed the UCT, TRC, and the RIM test.

The OUCC took issue with several of Petitioner's proposed programs. First, the OUCC argued that Petitioner's TRC calculation methodology is flawed. Second, the OUCC argued that Petitioner's Appliance Recycling Program is not likely to succeed as designed. Finally, the OUCC argued that Petitioner's Weatherization Program provides little program detail and is designed to place all risk on ratepayers.

With regard to Petitioner's TRC calculation, OUCC witness Paronish argues that Petitioner is incorrectly excluding certain costs from the TRC calculations, artificially making the results look more favorable. The OUCC argues that Petitioner is improperly choosing to classify some items as customer incentives rather than program costs. In rebuttal testimony, Petitioner admits they calculate the TRC for all programs with equipment provided for free to the customer categorized as an incentive. Petitioner also acknowledges that the TRC results would be lower if all equipment costs are included. Petitioner did provide revised TRC results for the affected programs. All individual programs, with the exception of the Low Income Weatherization program, still pass the TRC, and the overall portfolio of programs also still passes the TRC test. It should be noted the Weatherization program did pass the initial TRC test. We agree with the OUCC that all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, should be included in this test.

With regard to the Residential Appliance Recycling Program, the OUCC argues that the Petitioner omits information including an explanation of why Petitioner proposes to reduce the incentive paid to customers from $50 to $20. Also, the OUCC argues that there is no explanation as to how many customers are expected to participate or why Petitioner believes this new amount will be sufficient to motivate participation.

The Company responds that prior to finalizing the 2014 EM&V results, the program increased the incentive level from $30 to $50 in late March 2014. But the 2014 EM&V results showed lower than anticipated impacts for both refrigerators and freezers. The Company finished out 2014 and continued in 2015 with the $50 incentive. In an effort to bolster program cost effectiveness for the 2016-18 filing, the Company reduced the incentive to $20 and also decreased program goals to reflect the 2014 EM&V results.

We agree the Residential Appliance Recycling Program changes proposed by the Company are reasonable because of their being based on EM&V results. We look forward to future EM&V analysis to better understand the effectiveness of these changes.

With regard to the Weatherization Program, the OUCC argues that Petitioner does not explain the reasoning or calculation of the $250 health and safety fund or any guidelines for it. Furthermore, the OUCC argues this expense is not DSM.

Company Witness Goldenberg responds that the health and safety dollars are a key enabler of EE for low-income customers. The two are inexorably linked in low-income programs and the Company is following established DOE guidelines involving health and safety issues. Without help for health and safety problems, many homes will need to be bypassed and will not be weatherized. They will coordinate with Community Action Agencies, to the extent possible, the repair of weatherization health and safety improvements up to $750 per home.

The evidence presented is that the health and safety component of the program is essential if a greater number of low income customers are to be able to take advantage of the EE program.

Accordingly, based on the evidence presented, the Commission finds that Petitioner's EE program is in the public interest as it is designed to reduce energy consumption and benefits customers by providing opportunities for them to manage their energy costs and reduce or defer future generation needs. The portfolio of programs provides energy efficiency opportunities for all customers, both residential and C&I customers, and are similar to programs offered by other utilities that have been successful in meeting their goals. We find that the public interest is also served by the continuation of cost-effective DSM programs until Petitioner files a plan that complies with the newly enacted requirements of Section 10(h).

We note that several of the parties recommended changes and additions to Petitioner's proposed programs. While we decline to require Petitioner to make any changes, we do encourage Petitioner to consider those additional recommendations and work with its OSB to make any appropriate changes within the flexibility authorized to the OSB or in developing DSM programs to be implemented in the future.

2. Lost Revenues. 170 IAC 4-8-6 provides that the Commission may allow a utility to recover its lost revenue from the implementation of DSM programs. Recovery of lost revenues is intended as a tool to remove the disincentive utilities would otherwise face as a result of promoting DSM in their territories. *Southern Ind. Gas & Elec. Co.,* Cause No. 43938 at 40-41 (IURC 8/31/12). In *Indianapolis Power & Light*, Cause No. 43911 at 11 (IURC 11/4/10), we explained that one reason bias may exist is because a supply-side resource choice is primarily

a capital expenditure while a demand-side resource choice is primarily an expense. Utility capital expenditures found to be used and useful provide both a return of and a return on such investments; whereas utility expenses that are authorized to be included in rates for recovery from customers provide only a return of the expenditure. This financial advantage of a traditional supply-side resource requires a base rate case proceeding before such recovery occurs while authority to recover specific demand-side program expenses is regularly approved in rate adjustment tracker proceedings in the intervals between base rate cases. We also noted that bias could result from what is known as the throughput incentive. The choice of a successful demand-side resource investment results in reduced throughput, i.e., sales, which reduces the utility's revenue collections. The choice of a supply-side resource does not produce such an effect.

The OUCC objects to Petitioner's recovery of lost revenues and offers the following arguments in support of its position: (1) lost revenues should not be approved under SEA 412 except for programs that pass the RIM Test; and (2) lost revenue recovery should not be authorized unless the utility demonstrates that it is not recovering its fixed costs. The CAC also objects to lost revenue recovery, for the following reasons: (1) a utility should be required to demonstrate that it is not recovering its fixed costs; (2) a utility should be required to include load growth, off-system sales, and changes in other revenue structures; and (3) lost revenue recovery should be limited to the shorter of the life of the measure or three years. With regard to this latter position, CAC argued that most other states do limit such lost revenue recovery; however, CAC's witness was unable to identify any states where lost revenue recovery was limited to a definite period of time by statute or rule, or even by Commission Order except in settled cases. In contrast, Petitioner emphasized that with energy efficiency programs, a utility by definition incurs lost revenues. A utility's costs of providing service includes both fixed and variable costs, and while variable costs are avoided when energy savings occur, fixed costs remain. Because a utility's volumetric rates include both fixed and variable costs, when energy savings occur and customers use less electricity, the utility naturally recovers fewer revenues and fewer fixed costs than it would otherwise. Further, these lost revenues persist for the life of the applicable energy saving measure, or until the utility's base rates are reset in a base rate case. In Petitioner's view, it is not a matter of "proving" that it is or is not recovering its fixed costs – the fact is, energy efficiency programs lead to lower revenues and lower fixed cost recovery, which is a disincentive to pursuing energy efficiency. This Commission has been clear that "the recovery of lost revenues is a tool to assist in removing the disincentive a utility may have in promoting DSM in its service territory." See In re Petition of NIPSCO, Cause No. 44496 (November 12, 2014); see also, 170 IAC 4-8-6 (c) and In re Petition of Southern Ind. Gas & Elec. Co., Cause No. 43938, at pp. 40-41 (IURC August 31, 2011). We have also repeatedly explained that because the purpose of lost revenue recovery is to return the utility to the position it would have been in absent implementation of DSM, simply eliminating lost revenue recovery when sales are higher than the levels used to develop a utility's current base rates would be contrary to this purpose. See 44496 Order at pp. 21-22 and 43938 Order at p. 41.

We note that the CAC also requested that the Commission initiate some type of formal process to develop a standard methodology for Indiana utilities to calculate lost revenues for an energy efficiency measure.

The OUCC and CAC seem primarily concerned with what Ms. Mims termed the Pancake Effect, which occurs when lost revenues caused by energy efficiency investments in different years aggregate. For example, if the weighted average measure life is 10 years for an efficiency measure, then the utility company, assuming there is no rate case in the interim, would still be collecting lost revenues in 2025 for measures installed in 2016, along with lost revenues for measures installed during 2017-2025. It should be kept in mind that the cumulative lost revenues to be recovered in a year will tend to flatten out around a steady state level if there are no significant changes in kWh saved.

The proposed annual EE budgets show lost revenue as a percentage of the total budget is approximately 40% for each year 2016-2018. CAC Witness Mims points out the lost revenue pancake effect for the Company has flattened out at approximately $25 million per year, with 2018 showing an absolute decline in lost revenues. However, she notes this reduction in lost revenue is caused by the Company pursuing less energy efficiency than it did in 2012 in GWh.

Although we have previously approved lost revenues over a measure's life or until a utility's next base rate case, whichever is shorter, Ms. Mims' and the other parties' concerns with pancaking and the increased length of time between base rate cases for utilities in Indiana raise a valid concern. Clearly, pancaking of lost revenue is much less of an issue in an environment where a utility comes in regularly, i.e., every three to five years, for a base rate case. When the Commission's DSM Rules were adopted in the early 1990's, the previous twenty years was characterized by routine and sometimes almost back-to-back rate case filings where utilities' rates were reset on a regular basis. Consequently, recovery of lost revenues at that time was viewed as a tool of limited duration until the utility filed its next base rate case in the not too distant future. However, in the years after adoption of the DSM Rules, utilities have been staying out for ten or more years before filing for a rate case. *E.g., Indianapolis Power & Light,* 19 years between Cause No. 38664 (IURC 8/23/95) and pending Cause No. 44576; *Southern Indiana Gas & Electric Co.,* 12 years between Cause No. 39871 (IURC 6/21/95) and Cause No. 43111 (IURC 8/15/07); *Duke Energy Indiana, Inc.*, last rate case was filed 13 years ago in Cause No. 42359 (IURC 5/18/04, rh'g denied 7/28/04).

Because we believe the parties raise a valid concern, we find that Petitioner's lost revenue recovery should be limited to: (1) four years or the life of the measure, whichever is less, or (2) until rates are implemented pursuant to a final order in Petitioner's next base rate case, whichever occurs earlier. We note that the CAC also requested that the Commission initiate some type of formal process to develop a standard methodology for Indiana utilities to calculate lost revenues for an energy efficiency measure. Because Section 10 authorizes the recovery of reasonable lost revenues to utilities with an approved energy efficiency plan and Section 10(q) requires the Commission to adopt rules implementing the requirements of Section 10, we fully expect that this issue will be addressed in that future rulemaking.

3. Shareholder Incentives. 170 IAC 4-8-7(a) provides that when appropriate, the Commission "may provide the utility with a shareholder incentive to encourage participation in and promotion of a demand-side management program."

The Company's current shareholder incentive was the result of a settlement and approved in Cause No. 43955 DSM 2. It consists of a tiered shareholder incentive with a cap of 110% and a floor of 75% for purposes of earning an incentive, meaning no incentive will be earned for performance above 110% of goals, and no incentive will be earned for performance below 75%.

The proposed incentive maintains a cap and floor but eliminates the performance tiers. The Company would be eligible to receive a 12% pre-tax return on its approved program costs, with a minimum performance requirement of 70%. With that scheme the Company would not receive any incentive if it fails to achieve 70% of the projected savings for the portfolio. The proposed incentive will not exceed 12% of 115% of the sum of the budgets of the approved portfolio. All programs that fail the UCT and pilot programs are excluded from the proposed incentive calculation.

The OUCC and CAC took issue with Petitioner's proposal for a shareholder incentive. The OUCC argued that the proposal should be rejected because a shareholder incentive should not be allowed for a utility that sets its own savings targets. The CAC also objects to incentives for demand response programs and recommends that instead of Petitioner's proposed incentive, the Commission should authorize a shareholder incentive limited to 5 to 10% of the UCT benefits from energy savings – and only if lost revenue recovery is limited to the shorter of 3 years or the life of the measure.

Based on the circumstances presented in this proceeding, we find that financial incentives should not be authorized at this time. In making this decision, we note the significant changes that have occurred in the offering of DSM programs over the past several years. Beginning in 2010, the Phase II Order required utilities to offer DSM programs designed to meet an overall goal of 2% annual cost-effective DSM savings within ten years. This energy savings goal was aggressive, and we recognized that as a reason for awarding performance incentives. *E.g., Southern Indiana Gas & Electric Co.,* Cause No. 43427 at 35 (IURC 12/16/09). However, the Phase II Order savings requirements were eliminated in 2014. Instead, beginning no later than calendar year 2017, utilities will be required to establish energy efficiency goals in accordance with Section 10 every three years.

As discussed above, Section 10 requires a utility's energy efficiency goals to be reasonably achievable, consistent with its IRP, and designed to achieve an optimal balance of energy resources in its service territory. Provided a utility's plan includes these goals and is approved by the Commission, Section 10(o) specifically authorizes a utility to recover reasonable financial incentives that encourage implementation of cost-effective energy efficiency programs, or eliminate or offset regulatory or financial bias against either energy efficiency programs or in favor of supply-side resources. However, as we found above, Petitioner failed to submit a plan as required by Section 10(h) and, as a result, is not entitled to the reasonable financial incentives authorized by Section 10. While we recognize that Petitioner would have been statutorily allowed to recover reasonable financial incentives if it had submitted a qualifying plan under Section 10, the DSM Rules provide the Commission with the discretion to allow financial incentives when it believes it is appropriate to do so. In this instance, we find that Petitioner has not provided sufficient evidence of the need for an incentive to encourage or promote its proposed EE programs.

4. Continuation of Deferred Accounting, Approval of Reconciliation and Rider 66-A and Associated Rider 66-A Changes. Petitioner requested approval of continued

authority to use deferred accounting on an ongoing basis until its plan costs are reflected in retail rates, to ensure proper matching of expenses with the rate recovery of such expenses through its EE Rider. Petitioner also proposed rate adjustments via Rider 66-A necessary to reconcile actual 2014 EE costs with actual revenues collected from customers for such costs, and to adjust reconciliations of 2012 and 2013 that were included in the DSM-2 case to reflect the results of EM&V in accordance with the settlement and Order approved in DSM-2. Additionally Petitioner proposed Tariff changes necessary to effectuate approval of the proposed 2016-2018 EE plan, reconciliations, and associated ratemaking treatment and cost recovery. No party to this proceeding opposed Petitioner's proposals in this regard (except as discussed elsewhere in this Order), and Petitioner provided evidence in support of all such proposals. The Commission accordingly finds that Petitioner should be authorized to continue to use deferred accounting for energy efficiency expenses and revenues to minimize the timing difference between cost and revenue recognition and actual recovery of its EE plan costs. Based on the evidence presented, the Commission also finds that Petitioner's calculations of its billing factors in Rider 66-A are accurate and appropriate, that Petitioner's proposed reconciliations should be approved, and that Petitioner's proposed Tariff changes should be approved.

5. Petitioner's Oversight Board. Petitioner requested that its OSB have discretion to approve program spending up to 15% of the total budget without seeking Commission approval. The OUCC recommended that the OSB overspend authority be limited to an amount not to exceed 10% of the total budget and in rebuttal Mr. Goldenberg agreed with this recommendation. Accordingly, we find that Petitioner's OSB have authority to approve program spending up to 10% of its approved budget without seeking additional Commission authority. The OUCC also recommended that Petitioner take minutes at each OSB meeting and Petitioner agreed to do so. Finally, as to Ms. Mims' recommendation that Duke Energy Indiana include the benefits of energy efficiency into its opt out communications, we encourage Petitioner to work with the OSB on this topic going forward.

6. EM&V. The evidence shows that Petitioner has proposed procedures to evaluate, measure, and verify the results of its energy efficiency programs. Moreover, the evidence shows that its EM&V procedures are similar to procedures we found reasonable and approved in past cases. The only issues raised with respect to Petitioner's EM&V related to the estimated cost of the EM&V, and the frequency of the EM&V reports. OUCC witness Paronish testified that Petitioner's EM&V schedule for the Low Income Weatherization program does not allow for results to be reviewed prior to the schedule for its next three-year filing in 2018. In rebuttal, Ms. Ham proposed to finalize the EM&V report no later than first quarter 2018. With regard to costs, Petitioner updated and significantly lowered its estimated EM&V cost in rebuttal testimony, as a result of receiving competitive bid information from vendors. With respect to the frequency of EM&V reports, we believe this issue has been adequately addressed by the Company in rebuttal. Moreover, we believe this issue can be addressed in our generic DSM rulemaking if necessary. Ms. Paronish recommends that the OSB have greater involvement in the EM&V process, including the selection of an independent vendor. We agree with the Company that it is not feasible for the OSB to be involved in vendor selections as Petitioner operates EE programs in multiple jurisdictions and employs a competitive bidding process for the EM&V work across all jurisdictions. Petitioner takes this approach in order to reduce overall EM&V costs. Thus, moving away from this approach may impact Petitioner's ability to lower EM&V costs.

Further, the OUCC requested bi-weekly meetings with the EM&V vendors. We decline to require bi-weekly meetings with the EM&V vendors as it is unclear how they will add value. Accordingly, we find that Petitioner has included comprehensive EM&V procedures with its plan and we find Petitioner's proposed EM&V procedures to be reasonable.

7. Small Business Impact. The Commission must consider, in accordance with 170 IAC 4-8-8, whether a plan such as Petitioner's proposed 2016-2018 Plan may give an unfair competitive advantage to the utility in the provision of energy efficiency programs. We note that the Company's proposed EE portfolio relies in large part on the use of trade allies and small businesses to support outreach and delivery of the programs. Therefore, we conclude that Petitioner's Plan will not provide an unfair competitive advantage as contemplated by 170 IAC 4-8-8.

8. Confidential Information. Petitioner filed a Motion for Protection of Confidential and Proprietary Information, which was supported by affidavits, showing Workpapers filed in this proceeding were trade secret information within the scope of Ind. Code § 5-14-3-4(a)(4) and Ind. Code § 24-2-3-2. The Presiding Officers made rulings from the bench finding such information confidential on a preliminary basis after which such information was entered into evidence under seal. Accordingly, we find that all such information should continue to be held confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2.

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

1. Petitioner's request for approval of its Energy Efficiency Plan pursuant to Section 10 is denied. Accordingly, Petitioner remains under the statutory obligation to file, beginning no later than calendar year 2017, a plan that satisfies the criteria of Section 10(h).

2. Petitioner is authorized to implement its proposed Energy Efficiency Programs, as approved herein, through December 31, 2018 or until Petitioner submits and receives approval of a plan under Section 10, whichever occurs earlier.

3. Petitioner's request for authority to recover program costs and lost revenues associated with the Energy Efficiency Programs through Petitioner's DSMA Mechanism is approved as modified herein.

4. Petitioner's request for authority to recover shareholder incentives is denied.

5. Petitioner's requested accounting and ratemaking proposals to recover and allocate associated program costs, lost revenues are hereby approved.

6. Petitioner's reconciliation of the costs incurred, including lost revenues, for both its Core and Core Plus programs, and applicable incentive amounts for Core Plus Programs only during 2014, with amounts actually collected from customers from Rider EE billings is hereby approved.

7. Petitioner's updated reconciliation of lost revenues for 2012 and 2013 is hereby approved.

8. Petitioner's request for timely recovery of all costs, including program costs and lost revenues associated with the its Energy Efficiency Plan and programs (including its Power Manager demand response programs), through Duke Energy Indiana's Rider 66-A is hereby approved, consistent with the terms of the Commission's Order herein.

9. Petitioner's request for continued authority to use deferred accounting on an ongoing basis until such costs are reflected in retail rates through Rider 66-A is hereby approved.

10. Petitioner's proposed Rider 66-A, including the billing factors contained therein, shall be and hereby is approved, consistent with the Commission's determinations herein.

11. The material submitted to the Commission under seal shall be and hereby is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29.

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

STEPHAN, HUSTON, AND ZIEGNER CONCUR; WEBER NOT PARTICIPATING; MAYS-MEDLEY DISSENTING WITH SEPARATE OPINION:

APPROVED:

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

Shala M. Coe
Acting Secretary to the Commission

MAYS-MEDLEY DISSENTING

As I indicated in the dissent to the Commission's December 30, 2015 Order in Cause No. 44634, in the past two legislative sessions, the General Assembly passed bills that significantly changed the way the Commission addresses energy efficiency program offerings by utilities. Specifically, the General Assembly enacted Ind. Code §§ 8-1-8.5-9 (2014) ("Section 9") and 8-1-8.5-10 (2015) ("Section 10"). The majority's decision finds that Duke Energy Indiana's energy efficiency program fails to comply with Section 10 but then uses Section 9 as a fail-safe to approve the plan anyway. Because I believe this is an improper use of the statutes, I respectfully dissent.