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**

SUBMISSION OF PETITIONER'S PROPOSED FORM OF ORDER

Duke Energy Indiana, Inc. ("Duke Energy Indiana"), by counsel, respectfully submits its Proposed form of Order in the above-captioned Cause to the Indiana Utility Regulatory Commission ("Commission").

Respectfully submitted,

DUKE ENERGY INDIANA, INC.

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing Submission was electronically delivered this 6th day of November 2015, to:

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ORDER OF THE COMMISSION

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

On May 28, 2015, Petitioner Duke Energy Indiana, Inc. ("Duke Energy Indiana," "Petitioner," or "Company") filed its Petition with the Indiana Utility Regulatory Commission ("Commission") initiating this Cause. In its Petition, Duke Energy Indiana 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 Commission 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 Commission issued a Docket Entry accepting and establishing an agreed upon procedural schedule for this proceeding. On July 21, 2015, Petitioner filed the Supplemental Testimony of Michael Goldenberg. 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 August 25, 2015, Petitioner submitted the Corrected Public Workpapers of Diana L. Douglas.

On September 3, 2015, the OUCC filed its case-in-chief testimony and the CAC filed certain of its case-in-chief testimony and a Motion for Administrative Notice. On September 8, 2015, the CAC filed Witness Smith's Testimony, Exhibits, and Workpapers. On September 9, 2015, the CAC submitted its Revision to Page 53 of CAC Exhibit 1. On September 16, 2015, the Commission granted the CAC's Motion for Administrative Notice.

On September 23, 2015, Petitioner filed its Notice of its Submission of Previously Submitted Confidential Exhibit and Workpapers no Longer Deemed Confidential. On September 24, 2015, Petitioner filed its Rebuttal Testimony and Exhibits and the Revised Public Workpaper 10 of Diana L. Douglas. 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. On October 8, 2015, Petitioner filed its Amended 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__.** Duke Energy Indiana 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. **__Relief Requested__.** In its Petition, Petitioner 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.

4. **__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 (as entered into evidence as Petitioner's Exhibit 1); Ms. Roshena M. Ham, Manager, Measurement and Verification for Petitioner (as entered into evidence as Petitioner's Exhibit 4); Ms. Karen K. Holbrook, Director, Program Performance for Petitioner (as entered into evidence as Petitioner's Exhibit 7); and Ms. Diana L. Douglas, Director, Rates & Regulatory Planning for Petitioner (as entered into evidence as Petitioner's Exhibit 9). Petitioner also introduced into evidence several documents that were granted administrative notice treatment by the Commission, including the prefiled Testimony, Exhibits and Workpapers of Diana L. Douglas in Cause No. 43955 (Petitioner's Exhibit Administrative Notice 12), Confidential Materials from the prefiled Testimony, Exhibits and Workpapers of Diana L. Douglas in Cause No. 43955 (Petitioner's Exhibit Administrative Notice 12C), prefiled Testimony, Exhibits and Workpapers of Diana L. Douglas in Cause No. 43079 DSM-6 (Petitioner's Exhibit Administrative Notice 13), prefiled Testimony, Exhibits and Workpapers of Diana L. Douglas in Cause No. 43955 DSM-1 (Petitioner's Exhibit Administrative Notice 14), Confidential Materials from the prefiled Testimony, Exhibits and Workpapers of Diana L. Douglas in Cause No. 43955 DSM-1 (Petitioner's Exhibit Administrative Notice 14C), prefiled Testimony, Exhibits and Workpapers of Diana L. Douglas in Cause No. 43955 DSM-2 (Petitioner's Exhibit Administrative Notice 15), Confidential Materials from the prefiled Testimony, Exhibits and Workpapers of Diana L. Douglas in Cause No. 43955 DSM-2 (Petitioner's Exhibit Administrative Notice 15C), prefiled Testimony and Exhibits of Michael Goldenberg in Cause No. 43955 DSM-1 (Petitioner's Exhibit Administrative Notice 16), prefiled Testimony and

Exhibits of Michael Goldenberg in Cause No. 43955 DSM-2 (Petitioner's Exhibit Administrative Notice 17), Commission Order in Cause No. 43955 dated March 21, 2012 (Petitioner's Exhibit Administrative Notice 18), Commission Order in Cause No. 43079 DSM-6 dated December 19, 2012 (Petitioner's Exhibit Administrative Notice 19), Commission Order in Cause No. 43079 DSM-6 S1 dated March 21, 2013 (Petitioner's Exhibit Administrative Notice 20), Commission Order in Cause No. 43955 DSM-1 dated January 15, 2014 (Petitioner's Exhibit Administrative Notice 21), Commission Order in Cause No. 43955 DSM-1 dated March 30, 2014 (Petitioner's Exhibit Administrative Notice 22), Commission Order in Cause No. 43955 DSM-2 dated December 30, 2014 (Petitioner's Exhibit Administrative Notice 23), the Evaluation, Measurement and Verification Reports filed in Cause No. 42693 S1 on May 2, 2014 (Petitioner's Exhibit Administrative Notice 24), Duke Energy Indiana's 2013 Integrated Resource Plan submitted to the Commission on November 1, 2013 (Petitioner's Exhibit Administrative Notice 25), and Confidential Portion of Duke Energy Indiana's 2013 Integrated Resource Plan submitted to the Commission on November 1, 2013 (Petitioner's Exhibit Administrative Notice 25C).

In his testimony, Mr. Goldenberg addressed Senate Enrolled Act 412 ("SEA 412"), codified in part at I.C. 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 Cause. No. 42693 S1 ("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 Duke Energy Indiana. 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 its 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% over 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 as outlined below:

Duke Energy Indiana 2016 - 2018 Energy Efficiency Programs	
Residential	**Non-Residential**
*Smart $aver® Residential	Smart $aver® Non-Residential Prescriptive
Agency Assistance Portal	Smart $aver® Non-Residential Custom Incentive
Appliance Recycling	**Small Business Energy Saver
Energy Efficiency Education for Schools	*Power Manager® for Business
Low Income Neighborhood	
**Low Income Weatherization	
Multi-Family Energy Efficiency Products & Services	
My Home Energy Report	
Residential Energy Assessments	
Power Manager®	
**Power Manager® for Apartments	
Key: * Modified Program ** New Program	

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 Duke Energy 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 - under the Smart $aver® umbrella, the HVAC programs have been redesigned to reflect current minimum efficiency standards. Additionally, heat pump water heaters, variable speed pool pumps, smart thermostats, quality installation Retail Lighting and Single Family Water Measures have been added.
- Low Income Weatherization – this new feature complements Petitioner's existing low income program by working with local agencies to administer the program and implement energy saving measures that may include new equipment and shell improvements.
- Power Manager for Apartments – this new program brings the customer and system benefits available from air conditioning and water heating direct load control devices to both apartment tenants and their management/ownership.

For C&I customers, the following programs have been added to the portfolio:

- Small Business Energy Saver – this program effectively removes barriers usually seen with existing small non-residential facilities by offering a turn-key EE offering that facilitates the direct installation of EE measures and minimizes financial obstacles with significant upfront incentives from Petitioner to offset the cost of projects.
- Power Manager for Business - this program delivers both customer and system benefits from air conditioning load control. It also has the potential for energy savings from a Wi-Fi enabled thermostat for small or medium sized business customers.

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 Duke Energy 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 approximately19 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 that Petitioner's goals for 2016-2018 are as follows:

Duke Energy Indiana Energy Efficiency Goals*

	2016	2017	2018	2016-2018
MWH Savings	206,317	207,765	195,656	609,739
MWH as % of 2014 Total Sales	0.7%	0.7%	0.6%	
MWH as % of 2014 Eligible Sales	1.0%	1.0%	1.0%	
Gross MW Savings	96	101	105	
Total 2014 Retail Sales	30,347,904.16			
2014 Retail Sales Less Opt-Out	20,416,304.31			

* *All Numbers are Shown at the Plant*

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.

Mr. Goldenberg also testified that SEA 412 requires Petitioner to post an electronic copy of its filing on its website and provided the following address to where one could locate such posting: http://www.duke-energy.com/investors/DSM-Petition.asp. Mr. Goldenberg concluded his supplemental testimony by stating that, in his opinion, Petitioner's Proposed EE Plan meets the requirements of SEA 412.

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 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

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

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 utility 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 Test - 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-Participants 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 testified that as a result of the program analysis, Petitioner proposed the following set of cost-effective programs:

Cost-Effectiveness Scores for Proposed Programs/Measures

Program	UCT	TRC	RIM	PCT(1)
Residential				
Agency Assistance Portal	1.90	3.05	0.66	
Appliance Recycling Program	1.01	1.20	0.54	
Energy Efficiency Education Program for Schools	1.38	1.90	0.74	
Residential Energy Assessments	2.07	2.52	0.98	
Multi-Family EE Products & Services	1.46	1.69	0.65	
My Home Energy Report	1.68	1.68	0.74	
Low Income Neighborhood	1.02	2.39	0.60	
Smart $aver® Residential	1.98	2.72	0.70	10.52
Low Income Weatherization	0.35	1.12	0.28	
Power Manager®	4.53	6.06	4.53	
Power Manager® for Apartments	2.21	3.35	2.21	
Non-Residential				
Power Manager® for Business	1.94	2.85	1.72	
Smart $aver® Non-Residential Custom Incentive	4.86	1.00	1.02	1.43
Smart $aver® Non-Residential Prescriptive Incentive	1.86	1.34	0.84	2.02
Small Business Energy Saver	2.58	1.94	0.89	3.28

(1) The PCT score is not calculated when there are no participant costs.

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 Duke Energy 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 also outlined the previous ratemaking approved in Petitioner's EE Orders for use in the EE Rider as follows:

- Cost assignment to residential and non-residential rate groups based on the programs offered to each group and, within the non-residential rate group, based on whether and when customers were eligible to participate in the programs or whether and when customers opted out (or in) of participation;
- Inclusion of all customers in paying for the programs, including interruptible load to the extent not specifically excluded by contract language for customers with special contracts; and
- Cost allocation and rate development methodologies for conservation and demand response programs, which include the use of kWh sales as billing determinants for conservation programs for all rate classes and for all rate classes except high load factor ("HLF") for demand response programs; HLF will use non-coincident peak demands for demand response programs.

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 accessed.

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 Attachement 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.

5. <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 Standards 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 3 to 6% of program budgets. With Petitioner's EM&V vendor serving across all Duke Energy 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 overspend authority, without additional IURC approval, but limited to an amount not to exceed 10% of the Commission-approved total DSM Plan budget.

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 RFP's 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 I.C. 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:

1. Find Petitioner's proposed DSM plan unreasonable in its entirety pursuant to I.C. 8-1-8.5-10(m).

2. In the event the Commission declines to find the Plan unreasonable in its entirety, it should not allocate Plan costs only to ratepayers. 170 lAC 4-8-5(t) (Cost Recovery) states:

> In order to ensure that DSM program benefits and costs are allocated between utility shareholders, participants, and nonparticipants in a fair and economical way . . . .

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:

a. Because of the lack of evidence in its case in chief, the Commission cannot determine whether or not Petitioner's proposed programs are reasonable;

b. 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";

c. Petitioner's Residential Appliance Recycling Program is unreasonable and should be denied;

d. Petitioner's Weatherization Program is unreasonable and should be denied;

e. Petitioner's EM&V budget is excessive and should be limited to not more than 5% of Commission-approved program costs;

f. Petitioner's request for OSB authority to permit DSM program spending at 15% above Commission-approved program costs is excessive and should be denied;

g. Beginning immediately, Petitioner shall be responsible for recording minutes at each OSB meeting;

h. Petitioner shall fully include Petitioner's OSB in the EM&V selection process as discussed above; and

i. Petitioner's Power Manager programs are not "energy efficiency programs" as defined by I.C. 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 utilities 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 I.C. 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.

6. CAC's Case-in-Chief. The CAC presented Testimony of two witnesses in its case-in-chief: Ms. Natalie Mims of Mims Consulting LLC (entered into evidence as CAC Exhibit 1); and Mr. Ralph C. Smith, Senior Regulatory Consultant at Larkin & Associates, PLLC (entered into evidence as CAC Exhibit 2).

Ms. Mims claimed that Petitioner's Plan is not consistent with I.C. § 8-1-8.5-10 and recommended that the Commission reject Petitioner's Plan in this Cause because it cannot meet the requirements Section 10(j) or Section 10(h).

Ms. Mims noted that she is not an attorney, but upon her review of the statute, she did not believe that Petitioner's Plan captures what is "reasonably achievable" consistent with Petitioner's IRP, in accordance with Section 10(h). Ms. Mims argued that the IRP did not play enough of a role in establishing the EE Plan. Ms. Mims further noted that Petitioner is proposing energy savings between 196-208 gigawatt-hours each year, but noted that Petitioner's goal is lower than the Commission's goals in its December 9, 2009 Order and Petitioner's MPS.

Ms. Mims claimed that Petitioner should have made adjustments to its Action Plan to respond to opt-outs. Ms. Mims claimed that Petitioner should offer additional programs, including new construction and upstream manufactured home programs for residential customers, a school audit, and self-direct program for commercial and industrial customers.

Ms. Mims claimed that Petitioner's Plan did not meet the requirements of SEA 412 in regards to the "overall reasonableness" of the plan, based on Petitioner's request for lost revenues, which she believed is higher than the program costs. Ms. Mims again stated that she is not an attorney, but believed that the Commission must determine that the Plan is reasonable in its entirety, which she argued that the Commission should not do in this Cause.

Ms. Mims stated that SEA 412 codified lost revenues and claimed that in theory, she supports allowing Petitioner to recover lost revenues. However, Ms. Mims claimed that if lost revenues are allowed, it should be limited to the amount of decreased sales directly attributable to EE programs, and only to the extent that it impacts the Company's fixed cost recovery. Ms. Mims claimed that Petitioner has not provided evidence that it will under-recover because of DSM. Ms. Mims also argued that there should be a standard methodology in Indiana to uniformly calculate lost revenues, because Petitioner, NIPSCO, and Vectren calculate lost revenues in different ways. Ms. Mims also claimed that Petitioner should not recover lost revenues for more than three years, or the life measure, whichever is shorter.

Ms. Mims further argued that the "overall reasonableness" threshold is not met, because of the ongoing use of trackers and infrequent rate cases. Ms. Mims agreed that performance incentives are an effective tool to increase energy efficiency adoption, as part of the "three-legged stool" which also include cost recovery and lost revenues. However, she claims that because Petitioner set its own goals, it should be expected to achieve 100% of its goals. Further, she recommended a two-tiered savings incentive and a lower net benefit percentage. However, she felt that if the Commission shortens lost revenues, then the Commission should allow for a performance incentive.

Ms. Mims again stated that she was not an attorney, but believed that SEA 412 does not allow for recovery on "demand response" programs, and recommended that it deny Petitioner's request for performance incentives of its demand response programs. Ms. Mims also claimed that Petitioner's EM&V costs are too high and should work to reduce its EM&V to ~5% of its portfolio.

Mr. Smith claimed that Petitioner's base rates were set in 2004, and since that time, Petitioner has recovered additional costs through trackers without having a rate case, which he views as unfair to ratepayers. Mr. Smith claimed that Petitioner has not provided evidence that its EE programs have resulted in net decreases to retail sales, or that Petitioner does not have sufficient revenue to recover its authorized costs. He believes that Petitioner's sales have increased since the time when rates were set.

Mr. Smith claimed that lost revenues should not be assumed to exist and utilities should be required to demonstrate that lost revenues have incurred. Lost revenues are to reimburse a company for fixed costs that the utility would not be able to recover, because the utility's sales were used to establish its base rates in its last rate case. However, because he believes that Petitioner's sales have actually increased since its last rate case, the Commission should reject lost revenue recovery.

Mr. Smith also argued that lost revenues should be limited to measure life or three years, whichever is shorter. He also argued that an alternative remedy to a net decrease in sales is a new base rate case.

7. **<u>Petitioner's Rebuttal Testimony</u>.** Mr. Timothy Duff (as entered into evidence as Petitioner's Exhibit 6), Mr. Goldenberg (as entered into evidence as Petitioner's Exhibit 3), Ms. Ham (as entered into evidence as Petitioner's Exhibit 5), Ms. Holbrook (as entered into evidence as Petitioner's Exhibit 8), and Ms. Douglas (as entered into evidence as Petitioner's Exhibit 10), 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 I. C. § 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 costs 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 provides 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 I.C. § 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 I.C. § 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, I.C. § 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. I.C. § 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 I.C. § 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 I.C. § 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 I.C. § 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 I.C. § 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 I.C. § 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, I.C. § 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 I.C. § 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 I.C. § 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 I.C. § 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 updated the cost- effectiveness scores of the proposed programs to reflect the updated EM&V costs. The table below reflects these updates:

Cost-Effectiveness Scores for Proposed Programs/Measures

Program	**UCT**	**TRC**	**RIM**	**PCT$_{(1)}$**
Residential				
Agency Assistance Portal	1.90	3.05	0.66	>1.00
Appliance Recycling Program	1.01	1.20	0.54	>1.00
Energy Efficiency Education Program for Schools	1.50	2.12	0.77	>1.00

Residential Energy Assessments	2.15	2.64	1.00	>1.00
Multi-Family EE Products & Services	1.46	1.69	0.65	>1.00
My Home Energy Report	1.72	1.72	0.75	>1.00
Low Income Neighborhood	1.02	2.39	0.60	>1.00
Smart $aver® Residential	2.12	3.00	0.72	10.52
Low Income Weatherization	0.38	1.57	0.31	>1.00
Power Manager®	4.65	6.29	4.65	>1.00
Power Manager® for Apartments	2.21	3.35	2.21	>1.00
Non-Residential				
Power Manager® for Business	2.07	3.13	1.82	>1.00
Smart $aver® Non-Residential Custom Incentive	4.86	1.00	1.02	1.43
Smart $aver® Non-Residential Prescriptive Incent.	1.86	1.34	0.84	2.02
Small Business Energy Saver	2.68	2.00	0.90	3.28
All Programs Combined	2.56	2.24	1.13	3.39

(1) The PCT score cannot be calculated when there are no participant costs. In these instances, the program passes the PCT as indicated by the “>1.00” in the table above.

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.

The following chart presents the cost-effectiveness results using the alternate TRC calculation recommended by the OUCC. These scores also reflect the reduced EM&V costs.

<u>Cost-Effectiveness Scores for Proposed Programs/Measures</u>
<u>with Alternate TRC Calculation</u>

Program	**UCT**	**Alternate TRC**	**RIM**	**PCT$_{(1)}$**
Residential				
Agency Assistance Portal	1.90	1.90	0.66	>1.00
Appliance Recycling Program	1.01	1.20	0.54	>1.00
Energy Efficiency Education Program for Schools	1.50	1.50	0.77	>1.00
Residential Energy Assessments	2.15	2.15	1.00	>1.00
Multi-Family EE Products & Services	1.46	1.46	0.65	>1.00
My Home Energy Report	1.72	1.72	0.75	>1.00
Low Income Neighborhood	1.02	1.02	0.60	>1.00
Smart $aver® Residential	2.12	2.05	0.72	9.73
Low Income Weatherization	0.38	0.38	0.31	>1.00
Power Manager®	4.65	6.29	4.65	>1.00

Power Manager® for Apartments	2.21	3.35	2.21	>1.00
Non-Residential				
Power Manager® for Business	2.07	3.07	1.82	>1.00
Smart $aver® Non-Residential Custom Incentive	4.86	1.00	1.02	1.43
Smart $aver® Non-Residential Prescriptive Incent	1.86	1.34	0.84	2.02
Small Business Energy Saver	2.68	2.00	0.90	3.28
All Programs Combined	2.56	2.02	1.13	3.25

(1) The PCT score cannot be calculated when there are no participant costs. In these instances, the program passes the PCT as indicated by the ">1.00" in the table above.

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 I.C. § 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. Mr. 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 reducing this disincentive and providing 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 a 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 <u>will</u> 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, I.C. § 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 the February 28, 2015, 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 includes 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 are 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.

8. <u>Commission Discussion and Findings</u>. Duke Energy Indiana's Amended Petition indicates that it seeks relief under the following statutes and rules, among others: Ind. Code § 8-1-2-42(a), § 8-1-8.5-3, § 8-1-8.5-10, and 170 IAC 4-8-1 *et seq*. Commission decisions must be consistent with Indiana law and must be supported by specific findings of fact and sufficient evidence. *US Gypsum,* 735 N.E.2d at 795 (citing *Citizens Action Coalition of Ind., Inc.* v. *Public Serv. Co. of Ind., Inc.,* 582 N.E.2d 330, 331 (Ind. 1991)). In order to meet these requirements, we will discuss the various legal bases for our authority in this proceeding. In the context of these legal bases, we will discuss and determine whether or not the evidence presented by the Petitioner meets the applicable legal requirements. Finally, we will discuss and determine whether, given the relevant legal authority and the evidence presented by all parties, Petitioner's requested relief is reasonable and should be granted.

A. **<u>Senate Enrolled Act 412 (Ind. Code § 8-1-8.5-10)</u>.** SEA 412, codified at I.C. § 8-1-8.5-10, provides 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." *I.C.* § *8-1-8.5-10(h).* Such a plan may be submitted either as a part of a general rate case or as an independent proceeding. *I.C.* § *8-1-8.5-10(h).* "Plan" refers to the goals, programs, program budgets, program costs, and procedures submitted by an electricity supplier to the Commission under this statute. *I.C.* § *8-1-8.5-10(f).* A plan shall include energy efficiency goals, programs to achieve those goals, program budgets and costs, and EM&V procedures through an independent third-party evaluator. *I.C.* § *8-1-8.5-10(h).* SEA 412 defines "energy efficiency goals" to mean all energy efficiency produced by cost effective plans that are reasonably achievable, consistent with an electricity supplier's integrated resource plan, and designed to achieve an optimal balance of energy resources in an electricity supplier's service territory. *I.C.* § *8-1-8.5-10(c).* "Energy efficiency program" (or "program") means a program that is sponsored by an electricity supplier and is designed to implement energy efficiency improvements; "energy efficiency" means a reduction in electricity use for a comparable level of electricity service. The term "energy efficiency program" does not include a program designed primarily to reduce demand for limited intervals of time, such as during peak electricity usage or emergency conditions. *I.C.* § *8-1-8.5-10(b) and (d).* The energy efficiency plan itself must be cost effective, but may include a home energy efficiency assistance program for qualified customers whether or not the program is cost effective. *I.C.* § *8-1-8.5-10(c)and (h).*

The Commission must make the non-confidential contents of the electricity supplier's Petition available through the Commission's internet website. *I.C.* § *8-1-8.5-10(h).* Additionally, the electricity supplier must provide a copy of the Petition to the OUCC and post the non-confidential contents of the Petition and Plan on the electricity supplier's internet website. *I.C.* § *8-1-8.5-10(i).*

If, after notice and hearing, the Commission determines that the electricity supplier's Plan is reasonable in its entirety, the Commission must approve the Plan in its entirety, allow the electricity supplier to recover all associated program costs on a timely basis through a periodic rate adjustment mechanism, and allocate and assign costs associated with a program to the class or classes of customers that are eligible to participate in the program. *I.C.* § *8-1-8.5-10(k).* Upon a determination of reasonableness, the Commission shall also allow the utility to recover reasonable lost revenues and reasonable financial incentives that encourage implementation of cost effective energy efficiency programs or eliminate or offset regulatory or financial bias against energy efficiency programs or in favor of supply-side resources and lost revenues. *I.C.* § *8-1-8.5-10(o).*

I.C. § 8-1-8.5-10(j) sets forth a list of items the Commission must consider in making its determination as to whether the Plan is reasonable. These items include: (1) Projected changes in customer consumption of electricity resulting from implementation of the plan; (2) A cost and benefit analysis of the plan, including the likelihood of achieving the plan's energy efficiency goals; (3) Whether or not the plan is consistent with the state energy analysis and with the electricity supplier's most recent long range Integrated Resource Plan submitted to the Commission; (4) The inclusion and reasonableness of procedures to evaluate, measure, and verify the results of the energy efficiency programs included in the plan, including the alignment of the procedures with applicable environmental regulations, including federal regulations concerning credits for emission reductions; (5) Any undue or unreasonable preference to any customer class resulting, or potentially resulting, from the implementation of an energy efficiency program or from the overall design of the plan; (6) Comments provided by customers, customer representatives, the OUCC, and other stakeholders concerning the adequacy and reasonableness of the plan, including alternative or additional means to achieve energy efficiency in the electricity supplier's service territory; (7) The effect, or potential effect, in both the long term and the short term, of the plan on the electric rates and bills of customers that participate in energy efficiency programs compared to the electric rates and bills of customers that do not participate in energy efficiency programs; (8) The lost revenues and financial incentives associated with the plan and sought to be recovered or received by the electricity supplier; (9) The electricity supplier's current Integrated Resource Plan and the underlying resource assessment; and (10) Any other information the Commission considers necessary. *I.C.* § *8-1-8.5-10(j).*

Thus, under SEA 412, to approve a Plan, we must consider and answer two primary questions: (1) whether Petitioner's Plan meets the technical requirements of SEA 412; and (2) whether Petitioner's Plan is reasonable when considering the factors outlined in SEA 412.

(1) Whether Petitioner's Plan meets the technical requirements of SEA 412. The key questions we must ask *vis a vis* SEA 412's technical requirements are: (i) has the electricity supplier petitioned the Commission for approval of a plan prior to 2017? (ii) is the Petition for approval made either in a general rate case or an independent proceeding? (iii) has the electricity supplier provided a copy of its Petition to the OUCC and has the supplier posted the non-confidential contents of the Petition and Plan on its internet website? (iv) does the Plan include energy efficiency goals, programs to achieve those goals, program budgets and costs, and EM&V procedures through an independent third-party evaluator? and (v) are the programs "energy efficiency programs" within the meaning of SEA 412?

A review of the evidentiary record in this proceeding demonstrates that Petitioner has met the technical requirements under SEA 412, and for the reasons summarized below, we so find. First Petitioner has petitioned the Commission for approval of a Plan in 2015 – prior to 2017 as required by the statute. Second, Petitioner has petitioned for approval of its Plan in an independent proceeding, this Cause No. 43955 DSM-3. Third, the Petition and Amended Petition both include certifications that such Petitions were provided to the OUCC, and Mr. Goldenberg's Supplemental Testimony (as entered into evidence as Petitioner's Exhibit 2) indicates that Petitioner posted the non-confidential contents of its Petition and Plan on its internet website (http://www.duke-energy.com/investors/DSM-Petition.asp). We note that SEA 412 also requires that the Commission make the non-confidential contents of the electricity supplier's Petition available through the Commission's internet website, which we have done via our electronic document system (https://myweb.in.gov/IURC/eds/Guest.aspx?tabid=28).

Additionally, Petitioner's Plan includes energy efficiency goals, programs to achieve those goals, program budgets and costs, and EM&V procedures through an independent third-party evaluator. Mr. Goldenberg's direct and supplemental testimonies outline the Company's energy efficiency goals by year, in MWHs and as a percent of sales, for the three years from 2016 through 2018. Specifically, Petitioner's Plan established program goals for 2016-2018, as follows:

2016	206,317 MWH savings
2017	207,765 MWH savings
2018	195,656 MWH savings

Mr. Goldenberg's Direct Testimony (as entered into evidence as Petitioner's Exhibit 1) provides detailed descriptions of the Company's three-year Plan and the energy efficiency programs included in that Plan. Petitioner proposed sixteen programs for all participating market sectors in order to achieve these goals. As Mr. Goldenberg's Testimony reflects, these programs are as follows:

Residential Programs
- Agency Assistance Portal
- Appliance Recycling Program
- Energy Efficiency Education Program for Schools
- Low Income Neighborhood
- Low Income Weatherization
- Multi-Family EE Products and Services
- My Home Energy Report
- Residential Energy Assessments
- Smart $aver® Residential
- Power Manager®
- Power Manager® for Apartments

Non-Residential Programs
- Power Manager® for Business
- Small Business Energy Saver
- Smart $aver® Non-Residential Custom Incentive
- Smart $aver® Non-Residential Prescriptive Incentive
- Power Manager® for Business

Ms. Holbrook's Direct and Rebuttal Testimonies (as entered into evidence as Petitioner's Exhibits 7 and 8, respectively) set out the estimated program budgets and costs. Petitioner's program budget for the 3-year period 2016-2018 includes an estimate of $101.2 million in total estimated direct program costs including EM&V; $77.6 million in estimated lost revenues; and $11.5 million in estimated financial incentives. Ms. Douglas' Rebuttal Testimony estimates that the rate impact of the Plan on a typical residential customer in 2016 would be approximately a 1.1% rate increase. And Ms. Ham's Testimony (as entered into evidence as Petitioner's Exhibits

4 and 5) discusses in detail the procedures that will be used to evaluate, measure, and verify the programs, including the use of an independent third-party evaluator.

The OUCC took the position that Petitioner's Plan was not sufficiently detailed or transparent and thus did not meet the technical requirements of SEA 412. In support of this position, OUCC witness Paronish pointed out that the Company did not provide, in its case-in-chief, evidence such as the estimated number of participants and the estimated number of measures to be installed. In Ms. Paronish's view, without this information, it is impossible to determine how projected savings are derived by program or to check the reasonableness of those calculations. Further, Ms. Paronish stated that the program cost information does not specify items such as customer incentive amounts. Finally, she stated that the Company had only provided energy savings goals per program on a confidential basis, whereas other utilities provide that information publicly (Paronish, Public Exhibit 1, at p. 3).

The OUCC took specific issue with the level of detail in the Company's budget for health and safety dollars in connection with the Low Income Weatherization program; the level of detail provided for the refrigerator replacement program (also a part of the low income weatherization program); and the lack of criteria specified for determining whether to repair versus replace a home's furnace. Ms. Paronish also stated that the changes in the residential appliance cycling program – specifically, the reduction in incentive amounts – were not specified in sufficient detail, and that the Company had not demonstrated that the new incentive amounts would be sufficient to motivate customer participation (Paronish, Public Exhibit 1, at pp. 7-8).

In rebuttal, Mr. Goldenberg responded to the OUCC's contention that the Plan lacked sufficient detail and transparency. Mr. Goldenberg explained how Petitioner's case-in-chief met each of SEA 412's requirements. Additionally, Mr. Goldenberg testified that the Company provided all data necessary to determine program reasonableness, including cost-effectiveness results, program costs, overheads, EM&V costs, shareholder incentives, and lost revenues. He noted that the information provided by the Company in this proceeding is similar to information provided in past energy efficiency filings. He also noted that the OUCC had three months in which to seek data requests from the Company concerning any information they believed was necessary for them to evaluate Petitioner's Plan, and they did not request the information they now claim the Company failed to provide. In addition, Mr. Goldenberg provided additional detail concerning its Plan, including a breakdown of each measure by year (Goldenberg Rebuttal Testimony, Petitioner's Exhibit3, at pp. 2-7). Petitioner also ultimately filed all of its evidence publicly, even portions for which confidentiality had preliminarily been sought (except for confidential portions of its 2013 Integrated Resource Plan, which were submitted into evidence under seal via administrative notice).

Mr. Goldenberg also responded to the OUCC's program-specific arguments. He noted that the health and safety aspect of the Low Income Weatherization program is not a separate, stand-alone program, and he emphasized that the Company had provided sufficient information to determine the reasonableness of the overall program. Additionally, he explained that $75,000 per year has been budgeted for health and safety mitigation within the overall Low Income Weatherization program budget. Regarding the refrigerator replacement component of the Low Income Weatherization program, Mr. Goldenberg noted that the Company had responded to the

OUCC's questions through the discovery process and he included such data responses with his Rebuttal Testimony (Petitioner's Exhibit 3). With respect to the OUCC's objection to a lack of detail about criteria to be used to determine whether to repair or replace a home's furnace, Mr. Goldenberg noted that, in a discovery response, the Company had indicated to the OUCC that the Company would work with its program partners to define the replacement process and specific requirements. Further, in his Rebuttal Testimony, he elaborated that should a unit repair exceed the $600 amount, or in the event the system is not worth repairing based on existing age and efficiency, a replacement would be considered; but, 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. Regarding the appliance recycling program, Mr. Goldenberg explained that the program has been successful in terms of participation and changing customer behavior, but that EM&V results dictated a reduced incentive amount would be necessary to achieve cost-effectiveness. Accordingly, the Company's current Plan reflects both a reduced participant incentive and reduced participation. Future EM&V results will determine the ultimate fate of this program (Goldenberg Rebuttal Testimony, Petitioner's Exhibit 3, at pp. 7-8 and 10-11).

We conclude that the evidence presented by Petitioner meets the technical requirements of SEA 412. As required by SEA 412, the Company's evidence presents a Plan that includes energy efficiency goals, programs to achieve those goals, program budgets and costs, and EM&V procedures through an independent third-party evaluator. The Company's evidence includes significant detail about how the goals were developed, descriptions of the programs, costs and budgets, and EM&V procedures. While the OUCC may have had additional questions about certain aspects of the programs, the costs, etc., that is the purpose of the discovery process. A utility is not required to anticipate and address in its case-in-chief every possible question the OUCC or intervenor may have; that would be an impossible standard to meet, and is not required.

The OUCC also took the position that certain aspects of Petitioner's Plan did not qualify as "energy efficiency programs" within the meaning of SEA 412 – specifically, the health and safety aspects of the Low Income Weatherization program, and the "Power Manager" demand response programs. In support of this latter position, OUCC witness Paronish stated that, because SEA 412 defines "energy efficiency programs" in a manner that excludes demand response programs, Petitioner's "Power Manager" programs should not be eligible for financial incentives or lost revenues (Paronish, Public Exhibit 1, at pp. 8 and 12-13).

In rebuttal, Company witness Goldenberg testified that the health and safety aspects of the Low Income Weatherization program are integral to the achievement of energy savings and should be considered demand-side management. He pointed out that the program follows established Department of Energy guidelines involving health and safety issues, and without the ability to help low-income customers with health and safety, many homes will be bypassed and not have the opportunity to be weatherized. Repairs of health and safety issues such as warped door frames, broken windows, small roof leaks, plumbing leaks, structural repairs, and electrical repairs will allow energy saving insulation and other weatherization materials to be installed properly for low income customers.

On the issue of what qualifies as an "energy efficiency program" under SEA 412, Company witness Duff pointed out that while SEA 412 defines "energy efficiency programs" as Ms. Paronish noted, the statute does not preclude the Commission's consideration of demand saving programs and measures. He noted that some programs are hybrid mixtures of demand and energy savings and suggested that technological advances are leading to more of these hybrid demand/energy saving programs. He also emphasized that SEA 412 requires that consideration be given to the consistency of the utility's Plan with its IRP, and he noted that the Company's IRP includes and relies on demand response programs in addition to pure energy savings programs.

In our view, SEA 412 is primarily focused on energy efficiency programs designed to deliver energy savings rather than programs that are primarily designed to shift customers' energy usage. At the same time; however, SEA 412 in no way precludes the Commission from approving demand response programs or ratemaking for such programs as part of a utility's overall portfolio of programs that is designed to be consistent with its IRP. As is discussed in greater detail later in this Order, we have authority to approve such programs and ratemaking for such programs under other statutes and rules.

(2) Whether Petitioner's Plan is reasonable. The next level of analysis under SEA 412 is the more qualitative analysis of whether the petitioning electricity supplier's plan is reasonable. In order to facilitate this more qualitative analysis, SEA 412 directs the Commission to consider a number of specific factors, focused on: the cost-effectiveness of the plan; the projected energy savings impacts associated with the plan; the likelihood of achieving the plan's energy efficiency goals; whether or not the plan is consistent with the state energy analysis and with the electricity supplier's most recent Integrated Resource Plan; the reasonableness of the EM&V procedures; the impacts of the design of the plan on different customers; the impacts of the plan on the supplier's electricity rates and bills for both program participants and non-participants; the lost revenues and financial incentives associated with the plan; and comments provided by customers, customer representatives, the OUCC, and other stakeholders concerning the plan. Based on the evidence presented and our consideration of each of these factors, we conclude and find that Petitioner's Energy Efficiency Plan is reasonable in its entirety and should be approved. Our findings concerning each of SEA 412's required factors for our consideration is discussed in detail below.

(i) Projected changes in customer consumption of electricity resulting from implementation of the Plan. Petitioner presented its goals, discussed above, in terms of MWH savings, thus demonstrating the projected changes in consumption of electricity. Petitioner also presented projected MWH reductions as percentage of sales, as well as a percentage reduction of MWH of eligible sales, accounting for those customers who have opted out of participation (Goldenberg Supplemental Testimony, Petitioner's Exhibit 2, p. 3).

CAC contended that Petitioner's Plan would not capture all reasonably achievable energy efficiency (Mims Direct Testimony, CAC Exhibit 1, p. 5). Specifically, CAC witness Mims testified that Petitioner should seek more savings, consistent with the Company's most recent MPS (Id., p. 3). Ms. Mims discussed several additional programs that she believes the Company could implement and achieve additional energy savings (Id., p. 3). Mr. Goldenberg responded, noting that the energy savings proposed in this proceeding exceed the 2012-2014 goals under the Energizing Indiana paradigm (Goldenberg Rebuttal Testimony, Petitioner's Exhibit 3, p. 13). On cross-examination, Ms. Mims' agreed that the Company's proposed 2016-2018 energy savings goals are almost 80% of its 2012-2014 energy savings achievements – even with opt outs affecting all of the 2016-2018 programs (and only affecting the latter half of 2014 programs). Further, Mr. Goldenberg noted that Petitioner's most recent MPS (circa 2014) did not reflect customer opt outs or the elimination of the Phase II Order goals. He indicated a willingness to discuss additional programs with CAC and others through the OSB process, and to seek additional approvals and funding subsequent to this proceeding if the parties agree that implementation of additional programs is reasonable.

Based on the evidence, we find that Petitioner provided information necessary to determine changes in customer consumption of electricity from the implementation of its Plan. Further, based on the evidence and on SEA 412, we find that Petitioner's proposed energy savings from its 2016-2018 Plan are reasonable. Importantly, SEA 412 defines "energy efficiency goals" to mean all energy efficiency produced by cost effective plans that are reasonably achievable, consistent with an electricity supplier's Integrated Resource Plan, and designed to achieve an optimal balance of energy resources in an electricity supplier's service territory. *I.C.* § *8-1-8.5-10(c).* SEA 412 does not require that a utility's energy efficiency goals be designed to achieve 100% of all possible energy efficiency in its service territory (or even 100% of all possible cost-effective energy efficiency). Nor does it require that a utility's Plan be judged against a MPS. Rather, it requires that the utility's Plan be cost-effective, reasonably achievable within the context of the utility's IRP, and reasonably balanced between supply-side and demand-side resources. Petitioner's Plan meets this standard. We do, however, recognize that energy efficiency program design and implementation is an ongoing and dynamic process and we encourage the parties to continue to discuss and explore ways to optimize programs and cost-effective energy savings.

(ii) <u>A cost and benefit analysis of the Plan, including the likelihood of achieving the Plan's energy efficiency goals</u>. The Company presented evidence explaining how it modeled its Energy Efficiency Plan and programs, how it calculated and applied the four primary cost-benefit tests (PCT, UCT, TRC Test, and RIM Test). The evidence demonstrated that all of the Company's proposed programs and the Plan as a whole pass the PCT; all programs (except the Low Income Weatherization program) and the Plan as a whole pass the UCT; all programs (except the Low Income Weatherization program) and the Plan as a whole pass the TRC Test; and the Plan as a whole passes the RIM Test. Based upon this evidence, we find that Petitioner has presented a thorough cost and benefit analysis of its Plan. We also find that Petitioner's Plan is cost-effective, both because I.C. § 8-1-8.5-10(h) provides that low-income programs do not have to be cost effective and because aside from that program, Petitioner's programs pass the PCT, UCT and TRC Tests and Petitioner's Plan as a whole passes all four tests. We further find that because all of the programs pass the PCT – meaning, program participants will be better off if they participate in the program – the Company has a reasonable likelihood of achieving its Plan's energy efficiency goals. As pointed out by Mr. Goldenberg, Petitioner's historical energy efficiency program achievements also support this finding.

The OUCC took issue with two aspects of the Company's cost/benefit analyses. First, the OUCC took the position that in order for a program to be eligible for recovery of lost revenues and financial incentives, it must pass the RIM Test. We will discuss this issue later in our Order. Second, OUCC witness Paronish testified that the Company was misapplying the TRC Test in certain circumstances. Specifically, Ms. Paronish stated the TRC calculation should be performed differently for programs where the customer has no out-of-pocket expense for the efficient equipment provided by Petitioner. In those programs, Petitioner calculated the TRC with the free equipment cost categorized as an incentive (and incentives are excluded from the TRC Test). Ms. Paronish suggests that the TRC calculation for these programs should be calculated with the equipment costs included as a program cost (and included in the TRC Test calculation) rather than as an incentive. Ms. Paronish pointed to clarifying guidance from the California Public Utilities Commission regarding this issue. In response, Petitioner explained that it calculated the TRC Test consistent with its past calculations, categorizing equipment provided to the participation as an incentive. Petitioner's witness Ham also provided evidence in rebuttal showing that that calculating the TRC Test as advocated by Ms. Paronish did not change the TRC Test results; all programs (except the Low Income Weatherization program) and the Plan as a whole were still cost-effective under the TRC Test.

Given that all the programs (except Low Income Weatherization, which is not required to be cost-effective under SEA 412) are cost-effective whether the TRC Test is calculated as Petitioner proposed or as OUCC proposed, and given that the TRC Test is but one of several cost-benefit tests considered by Petitioner and this Commission, we find that this issue is effectively moot in this case. However, we believe Ms. Paronish's point has merit and we will consider this issue in our pending rulemaking relating to DSM. In that context, any changes in cost-benefit calculations will be applied to all utilities through generic rules.

(iii) <u>Whether or not the Plan is consistent with the state energy analysis and with the electricity supplier's most recent long range Integrated Resource Plan submitted to the Commission</u>. The evidence in this case shows that the Company's current IRP (as of the date of its filing and hearing in this case) was its 2013 IRP, and the Company used its 2013 IRP as a basis for informing its Energy Efficiency Plan. For example, in the cost-effectiveness analysis under taken for this filing, the avoided energy and capacity costs were consistent with those used in the Company's 2013 IRP. The evidence also shows that, since the development of its 2013 IRP, SEA 340 and SEA 412 were passed into law and opt outs by large customers were authorized. Mr. Goldenberg testified that a significant amount of Petitioner's large industrial load has chosen to opt out of participating in its energy efficiency programs – over 80% of eligible large industrial load has opted out, which is approximately 49% of the Company's total commercial and industrial load.

We find when comparing the incremental estimated energy efficiency impacts from Petitioner's 2013 IRP low case for the period 2016-2018 (503,481 MWHs) with its estimated 2016-2018 energy efficiency impacts from the plan proposed in this proceeding (609,738 MWHs), we see an increase of 21%, which is impressive when considering the level of opt outs. (Compare page 53 of 2013 IRP and Mr. Goldenberg's testimony.) Specifically, the plan exceeds but is most consistent with the IRP's "low" energy efficiency case – the case that modeled lower spending and lower impacts from energy efficiency programs. Further, we note that IRP are point in time analysis; such analysis is modified regularly. Duke Energy Indiana's latest IRP was most recently filed in November 2015 and was therefore being developed in parallel with this EE Plan. Duke Energy Indiana committed to review with the OSB its most recently filed IRP and how the budget and impacts in this current EE Plan portfolio compare. We encourage the Company to provide information on this to both the OSB and the Commission in future energy efficiency filings, such as annual Rider update filings.

Similarly, the evidence shows that the Company's plan is consistent with the State of Indiana's energy analysis. The 2013 state energy forecast indicates that DSM projections were estimated from utility IRP filings, among other things (*See Indiana Electricity Projections: The 2013 Forecast*, pages 1-5; December 2013). Accordingly, we find that Petitioner's plan is reasonably consistent with both its most recent (2013) IRP and the state's energy analysis. We would also recommend that the Company discuss with its OSB (1) any significant changes between its 2013 and 2015 IRPs, and (2) any potential changes that should be made to its 2016-2018 energy efficiency plan as a result of such changes between its IRPs. In addition, the Company should file a report with the IURC in this Cause summarizing changes, if any, to the 2016-2018 energy efficiency plan that the OSB agree should be made during the 2016-2018 period. If the OSB recommends any changes, Duke Energy Indiana agrees to seek IURC approval of such changes.

(iv) <u>The inclusion and reasonableness of procedures to evaluate, measure, and verify the results of the Energy Efficiency programs included in the Plan, including the alignment of the procedures with applicable environmental regulations, including federal regulations concerning credits for emission reductions</u>. The evidence shows that Petitioner has proposed comprehensive 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 programs 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 prior to its 2018 three-year filing. 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. Finally, we note that SEA 412 requires us to consider whether EM&V procedures are aligned with applicable environmental regulations. The U.S. EPA has not yet developed final rules with respect to EM&V procedures for energy efficiency programs. In August 2015, the EPA issued guidance related to EM&V procedures associated with the Clean Power Plan and currently is seeking public input.[2] Therefore, no applicable final rule or guidance exists; thus, there is nothing currently to align with, and most likely there will not be a final rule or guidance until at least 2016 or after. 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.

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[2] *See Evaluation Measurement and Verification (EM&V) Guidance of Demand Side Management (DSM) Draft for Public Input*, U.S. Environmental Agency (August 3, 2015).

(v) Any undue or unreasonable preference to any customer class resulting, or potentially resulting, from the implementation of an Energy Efficiency program or from the overall design of the Plan. The evidence shows that Petitioner's Plan offers programs for all major customer sectors – residential (including low income), commercial, and industrial customers. Further, Petitioner's proposal is to allocate costs on a class basis. No party took issue with the Company's proposed allocation of Energy Efficiency Plan costs. According, we find that Petitioner's Plan and programs will not create any undue or unreasonable preference to any customer class and we approve Petitioner's allocation proposal.

(vi) Comments provided by customers, customer representatives, the OUCC, and other stakeholders concerning the adequacy and reasonableness of the Plan, including alternative or additional means to achieve energy efficiency in the electricity supplier's service territory. The OUCC and CAC filed testimony of several witnesses commenting on the adequacy and reasonableness of Petitioner's Plan and programs. CAC witnesses discussed alternative or additional means of achieving energy efficiency in Petitioner's service territory. As should be clear by this Order, we have thoroughly considered the comments provided by such stakeholders in arriving at our decision in this case. We would also note that Petitioner's OSB (which is not required by SEA 412) provides an additional forum for continuing discussions about these issues.

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. As to the OUCC's recommendation for greater involvement in the EM&V process, we encourage the OSB to develop guidelines for its EM&V procedures.

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.

(vii) The effect, or potential effect, in both the long term and the short term, of the Plan on the electric rates and bills of customers that participate in Energy Efficiency programs compared to the electric rates and bills of customers that do not participate in Energy Efficiency programs. SEA 412 explicitly requires us to consider the rate and bill impacts on both participating customers and non-participating customers. The evidence in this case shows that all programs pass the PCT, and that participants will, therefore be, better off participating than not participating, in terms of achieving energy efficiency savings and thereby lowering their electricity bills. The evidence also demonstrates that the Plan as a whole passes both the UCT and the RIM Tests. This indicates that the utility system as a whole is better off with this Plan than without it, and that customers as a whole, including non-participants, will be better off with this Plan. Collectively, these cost-benefit test results indicate that while certain programs in the Plan may cause rates to increase for non-participating customers, participants' bills will be lower than they otherwise would have been and non-participants' rates would rise even more if alternative resources were employed in place of the Plan. In sum, we find that the Plan will have positive impacts on rates and bills of both participants and non- participants.

(vii) The lost revenues and financial incentives associated with the Plan and sought to be recovered or received by the electricity supplier. Petitioner presented its proposals for recovery of lost revenues and for financial incentives associated with the Plan, including rationales for its proposals and estimated impacts of such proposals on revenue requirements. The OUCC and CAC took issue with various aspects of Petitioner's ratemaking proposals. We discuss these issues in greater detail later in this Order.

(viii) The electricity supplier's current Integrated Resource Plan and the underlying resource assessment. Petitioner requested, and we granted, administrative notice of its 2013 IRP. Petitioner's evidence also discusses how its Energy Efficiency Plan and programs are informed by its IRP. As discussed in greater detail in item (iii) above, we have taken into consideration Petitioner's IRP and the resource assessment underlying that IRP in our decision-making in this case.

(ix) Any other information the Commission considers necessary. Based on the evidence submitted by the parties, we do not believe any other information is necessary for us to reach our conclusions about the reasonableness of Petitioner's Energy Efficiency Plan.

(3) Recovery of Lost Revenues and Financial Incentives. SEA 412 provides that if, after notice and hearing, the Commission determines that the electricity supplier's plan is reasonable in its entirety, the Commission must approve the plan in its entirety, allow the electricity supplier to recover all associated program costs on a timely basis through a periodic rate adjustment mechanism, and allocate and assign costs associated with a program to the class or classes of customers that are eligible to participate in the program. *I.C.* § *8-1-8.5-10(k).* SEA 412 further provides that, upon a determination of reasonableness, the Commission shall also allow the utility to recover reasonable lost revenues and reasonable financial incentives that encourage implementation of cost effective energy efficiency programs or eliminate or offset regulatory or financial bias against energy efficiency programs or in favor of supply-side resources and lost revenues. *I.C.* § *8-1-8.5-10(o).* Given that we have found Petitioner's Plan to be reasonable in its entirety, and have approved the Plan in its entirety, we must next address the appropriate ratemaking for the Plan – keeping in mind that SEA 412 directs us to allow recovery of all associated plan costs, including reasonable lost revenues and financial incentives, on a timely basis through a periodic rate adjustment mechanism.

(A) Lost Revenues. 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 life 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. Senate Enrolled Act 412 specifically provides for eliminating such disincentive.

Petitioner also pointed out that reliance on the RIM Test would greatly reduce the amount of energy savings that would occur in Indiana. Additionally, Petitioner noted that even if it were relevant to lost revenue recovery, the Company does not retain its off-system sales profits; rather, those are credited to retail customers through a tracking mechanism.

Even prior to SEA 412, 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.

SEA 412 strengthens our obligation to grant lost revenue recovery. Whereas prior to SEA 340 and SEA 412 there was no legislative directive regarding lost revenue recovery, now Ind. Code ch. 8-1-8.5 explicitly discusses and requires recovery of reasonable lost revenues associated with approved energy efficiency programs and plans. Notably, SEA 412 defines the term "lost revenues" narrowly (and consistent with the Commission's current DSM rules): the difference, if any, between revenues lost and the variable operating and maintenance costs saved. Nowhere in this definition or elsewhere in SEA 340 or SEA 412 are customer load growth, off-system sales, or changes in other revenue structures mentioned. Nowhere in SEA 340 or SEA 412 are any sort of time limits on lost revenue recovery mentioned, either. For these reasons, we reject the OUCC's and CAC's arguments that SEA 412 does not authorize lost revenue recovery in this case and we reject CAC's argument that lost revenue recovery should be artificially limited to three years.

We also reject the OUCC's somewhat tortured interpretation of SEA 412 as allowing lost revenue recovery only for programs that pass the RIM Test. While SEA 412 does require programs to be cost-effective, the statute does not prescribe or even describe any specific cost-effectiveness tests or calculations for plans and programs, let alone for lost revenue recovery. Interpreting SEA 412, as the OUCC proposes, is not only contrary to the plain meaning of the statute, such an interpretation would produce results that we do not believe are consistent with the public interest. Such an interpretation would run counter to SEA 412's clear intent to allow lost revenue recovery and would also discourage utility pursuit and implementation of energy efficiency programs.

Petitioner has presented us with a reasonable proposal for lost revenue recovery. The Company's proposal will accurately estimate the revenues (fixed costs) "lost" due to implementation of its energy efficiency programs, and will utilize EM&V results, including free rider impacts, to precisely calculate the actual lost revenues resulting from such programs. We note that no party took issue with the calculations or mechanics of the Company's lost revenue recovery proposal. Petitioner's proposal will also limit lost revenue recovery to the life of the measure (or the effective date of an intervening rate case). According, we find and conclude that Petitioner's lost revenue recovery proposal is reasonable and should be approved.

<u>Financial Incentives</u>. Under SEA 412, upon a determination of reasonableness, the Commission shall also allow the utility to recover reasonable financial incentives that encourage implementation of cost effective energy efficiency programs or eliminate or offset regulatory or financial bias against energy efficiency programs or in favor of supply-side resources and lost revenues. *I.C.* § *8-1-8.5-10(o).*

The OUCC and CAC took issue with Petitioner's proposal for a financial incentive. The OUCC argued that the proposal should be rejected because, as with lost revenues, they believe that SEA 412 only allows financial incentives for programs that pass the RIM Test; and (2) a shareholder incentive should not be allowed for a utility that sets its own savings targets. Additionally, the OUCC argues that demand response programs should not be eligible for incentives because SEA 412 only applies to energy efficiency programs. The CAC also objects to incentives for demand response programs and recommends that instead of Petitioner's proposed incentive, the Commission should authorize a performance 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.

As Petitioner points out, financial incentives have been granted by the Commission historically – both incentives structured as proposed by the Company herein and shared savings incentives. Further, the Company demonstrated that its proposed incentive is comparable to the return it is authorized to earn on supply-side investments. Moreover, as with lost revenue recovery, SEA 412 now explicitly directs the Commission to approve reasonable financial incentives in connection with approved energy efficiency programs. Specifically, SEA 412 requires us to approve reasonable financial incentives that either encourages implementation of cost effective energy efficiency programs, or that eliminate or offset regulatory or financial bias against energy efficiency programs or in favor of supply-side resources.

We again reject the OUCC's tortured implementation of SEA 412 so as to deny financial incentives for programs that do not pass the RIM Test; SEA 412 says nothing about the RIM Test or any other test. We note the irony of the OUCC's position: the OUCC argues that SEA 412 only allows incentives for programs that pass the RIM Test – generally demand response programs – and the OUCC also objects to financial incentives for demand response programs on the basis that SEA 412 does not apply to such programs.

While SEA 412 directs the use of reasonable financial incentives for approved plans, SEA 412 does not prescribe the structure of allowed financial incentives. Rather, the legislature has directed that we consider proposals in the context of whether or not they will encourage energy efficiency, and/or eliminate bias against energy efficiency or in favor of supply-side resources. While a performance incentive of the type advocated by CAC might also be acceptable, we believe the evidence here demonstrates that the Company's proposed financial incentive will both encourage implementation of energy efficiency and eliminate or offset regulatory or financial bias against energy efficiency or in favor of supply-side resources. Lost revenue recovery removes a disincentive in the pursuit of energy efficiency, but with lost revenue recovery alone, a utility is still financially incentivized to pursue supply-side resources for which it can earn a return for its investors. Financial incentives are needed to truly encourage energy efficiency and offset or eliminate the financial bias against such demand-side resources. In this case, Petitioner has demonstrated that its proposed incentive is precisely comparable to the return authorized for its investments in supply-side resources. And, under Petitioner's proposal, it bears the risk of not earning any financial incentive if it fails to achieve 70% of its energy efficiency targets. Moreover, the evidence demonstrates that Petitioner's energy savings targets remain robust and aggressive in light of the reality of large industrial customer opt outs. For these reasons, we do not find persuasive the OUCC's argument that the incentive proposal should be rejected because the Company has established its own targets. Indeed, SEA 412 requires electricity suppliers to establish their own energy efficiency goals. For all of these reasons, we conclude and find that the Petitioner's financial incentive proposal is reasonable and should be approved.

B. <u>Ind. Code § 8-1-2-42(a), § 8-1-8.5-3, and 170 IAC 4-8-1 et seq</u>. In addition to SEA 412 Petitioner has also sought its requested relief under the "pre-412" legal authority – Ind. Code § 8-1-2-42(a), 8-1-8.5-3, and 170 IAC 4-8-1 et seq. As we have approved the majority of Petitioner's Plan and ratemaking treatment under SEA 412, we need not dwell on these legal bases. However, we note that these bases also provide support for approval of Petitioner's Energy Efficiency Plan and programs, and associated ratemaking treatment including timely recovery through a rate adjustment mechanism of program costs, lost revenues, and financial incentives. *See, In Re Petition of Duke Energy Indiana for Approval to Offer EE Programs*, IURC Cause No. 43955 (March 21, 2012), in which the Commission approved, among other things, Petitioner's proposed Core Plus Program portfolio along with cost recovery (including lost revenues) and incentives through Rider EE. *See also In Re Petition of Duke Energy Requesting Approval of an ARP*, IURC Cause No. 43374 (Feb. 10, 2010), in which the Commission approved a Settlement Agreement where Duke Energy Indiana and the OUCC agreed that the Company shall collect lost revenues over the term of the Agreement until such time that a decoupling or alternative recovery mechanism is implemented or a general rate case is implemented.

Moreover, these legal bases provide us with authority to approve comparable treatment for Petitioner's proposed demand response programs. We interpret SEA 412 not as constraining our authority in this area, but simply as not applicable to our authority in this area. However, we have authority under section 42(a), section 3 of the Powerplant Construction Act, and our DSM rules to approve all types of demand-side management programs – both energy efficiency and demand response programs – and to approve ratemaking treatment for such programs, including lost revenue recovery and financial incentives. *See*, *In Re Petition of Duke Energy Indiana for Approval to Offer EE Programs*, IURC Cause No. 43955 (March 21, 2012), in approving Petitioner's portfolio cost recovery, lost revenues and incentives, the Commission also noted: "The Commission adopted the DSM rules providing guidelines for DSM cost recovery. The DSM rules were specifically designed to assist the Commission in its administration of the Utility Powerplant Construction Act, Indiana Code ch. 8-1-8.5, and to facilitate increased use of DSM as part of the utility resource mix" (at page 33.) *See also In Re Petition of NIPSCO for Approval of DSM*, IURC Cause No. 43912 (July 27, 2011), in which the Commission discussed that the purpose of its DSM administrative rules allowing incentives and lost revenues was to provide a "regulatory framework" that "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." (at page 22.) *See also In Re Petition of Duke Energy Indiana for Approval to Offer EE Programs*, IURC Cause No. 43955 (March 21, 2012), in which the Commission approved Duke's DSM programs which included both conservation ***and demand response programs***, and granted cost recovery, incentives and lost revenues for said programs.

Indeed, a review of our DSM rules, promulgated under Ind. Code ch. 8-1-8.5, demonstrates that program cost recovery and lost revenue recovery are available for all types of demand-side management programs, and that the only types of demand-side programs for which financial incentives are not appropriate are load retention and load building programs. See 170 IAC 4-8-1(e) and (g); 170 IAC 4-8-5, 4-8-6, and 4-8-7. Petitioner's demand response programs are neither load retention nor load building programs. Rather, they are highly cost-effective peak demand reduction programs that provide value to the Company's system and its customers. As such, they are consistent with the goals of the Powerplant Construction Act, and they are eligible for program cost recovery, lost revenue recovery, and financial incentives under our DSM rules. Accordingly, we conclude and find that Petitioner's "Power Manager" demand response programs should be approved as part of the Plan and Petitioner should be authorized to recover on a timely basis through its EE Rider associated program costs, lost revenues, and the financial incentives as proposed by the Company.

C. <u>Continuation of Deferred Accounting; Approval of Reconciliation and Rider 66-A Rates and Associated Rider 66-A Changes</u>. 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.

D. 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.

E. Ultimate Findings. Based on the evidence presented, we find that the Petitioner's Energy Efficiency Plan and programs, budgets, estimated costs, and EM&V procedures submitted in this proceeding are reasonable and in the public interest, and should be approved in their entirety, including approval of $300,000 for Petitioner to have a Market Potential Study performed. The proposed cost recovery, allocation methodology, and ratemaking and accounting treatment are consistent with applicable statutes, rules, and precedents and will produce just and reasonable rates. Additionally, the proposed Rider 66-A Tariff and the proposed Rider 66-A billing factors, as presented in Petitioner's testimony, should be implemented.

9. 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 I.C. § 5-14-3-4(a)(4) and I.C. § 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 I.C. § 5-14-3-4 and I.C. § 24-2-3-2.

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

1. Petitioner's proposed 2016-2018 Energy Efficiency Plan and programs (including its Power Manager demand response programs), and their respective proposed

costs and budgets, including $300,000 for its Market Potential Study, are approved as set forth herein.

2. Petitioner's accounting and ratemaking proposals to recover and allocate associated program costs, lost revenues, and shareholder financial incentives are hereby granted.

3. Petitioner's request to exclude its low-income weatherization program from its shareholder financial incentive proposal is hereby granted.

4. 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.

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

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

7. 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.

8. 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.

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

STEPHAN, HUSTON, MAYS-MEDLEY, WEBER AND ZIEGNER CONCUR

APPROVED:

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

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Brenda A. Howe
Secretary to the Commission