FILED
March 2, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC FOR (1) APPROVAL OF ITS PROPOSED PLAN FOR DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS FOR 2020-2023; (2) AUTHORITY TO RECOVER ALL PROGRAM COSTS, INCLUDING LOST REVENUES AND FINANCIAL INCENTIVES IN ACCORDANCE WITH IN. 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; (30 AUTHORITY TO DEFER ALL SUCH COSTS INCURRED UNTIL SUCH TIME THEY ARE REFLECTED IN RETAIL RATES; (4) REVISIONS TO STANDARD CONTRACT RIDER 66A; AND (5) INTERIM AUTHORITY TO CONTINUE OFFERING ITS CURRENT DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS UNTIL A FINAL ORDER IS ISSUED IN THIS CAUSE.	)	**CAUSE NO. 43955 DSM-08**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 1

PUBLIC (REDACTED) TESTIMONY OF OUCC WITNESS

JOHN E. HASELDEN

March 2, 2020

Respectfully submitted,

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TESTIMONY OF OUCC WITNESS JOHN E. HASELDEN
CAUSE NO. 43955 DSM 8
DUKE ENERGY INDIANA, LLC

I. INTRODUCTION

Q: Please state your name, business address, and employment capacity.

A: My name is John E. Haselden. My business address is 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204. I am a Senior Utility Analyst in the Electric Division of the Indiana Office of Utility Consumer Counselor ("OUCC"). I describe my educational background and professional work experience in Appendix A to my testimony.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: Yes. I have testified in a number of cases before the Commission, including: (1) base rate cases; (2) demand side management ("DSM") plan approvals; (3) various tracker cases (e.g. DSM, environmental compliance and Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") cases); (3) renewable energy project approval and declination of jurisdiction cases; and (4) applications for Certificates of Public Convenience and Necessity ("CPCN"). Please see Appendix A for my qualifications and experience.

Q: Does the OUCC have overarching concerns about Duke Energy Indiana's (DEI") proposed four-year DSM Plan ("DSM Plan" or "Plan") and rate recovery in this Cause?

A: Yes. The OUCC wants to emphasize the importance of making the correct decisions concerning the energy future of Indiana. Those decisions should be supported by facts and not an over-reliance on assumptions that may drive energy choice decisions in divergent directions. The Indiana General Assembly enacted HEA

1278 in 2019 and established the 21st Century Energy Policy Task Force ("Task Force") to explore the impact of fuel transitions and emerging technologies. The work of the Task Force is not complete. There may be significant changes recommended to the Integrated Resource Plan ("IRP") assumptions utilized by the Indiana utilities. While it is likely the energy landscape in Indiana <u>will</u> change, resource plans and commitments, such as this proposed DSM Plan, must remain flexible and also protect the interests of utility customers. In this DSM case, shareholder incentives, paid for by customers, are driven by assumptions about DEI's energy future which do not incorporate the likely consequences of the widely recognized energy transition. As proposed, there is no reconciliation of shareholder incentives reflective of costs that are actually avoided. This is especially troublesome given the uncertain future. Without such reconciliation, a utility has little incentive to make reasonable assumptions.

The proposed Plan includes $21.1 million in shareholder incentives and another $28.8 million in lost revenues. The OUCC finds the basis from which DEI calculates these numbers to be a combination of incorrect calculations and overstated assumptions. The OUCC is also concerned about the lack of transparency in the calculations and assumptions used by DEI. Discovering the assumptions and calculations for even one measure has required multiple data requests, meetings, and telephone conversations.[1] Even then, all questions cannot be answered. A utility must present a complete case-in-chief that thoroughly

[1] See Appendix B.

supports its request. This not only satisfies a utility's burden of proof, but also provides the basic level of transparency necessary to assess and evaluate the petition. The proposal makes significant changes to its current program without any explanation. The OUCC does note that the common denominator in these changes is an expansion and shift in focus from certain residential programs to programs that compensate DEI with higher shareholder incentives.

However, DEI's case-in-chief presents only a high-level description of the Plan and a summary statement indicating the programs contained therein are cost effective, without providing any supporting evidence. DEI requests approval of the Plan in its entirety notwithstanding problems with the underlying details unseen by the Commission or other parties. Some of the larger issues will be discussed in this testimony, but many more remain. In the recent past, the Commission has approved utilities' proposed tracker recovery filings over the OUCC's concerns regarding these issues. The Commission has suggested those concerns be addressed in the new DSM Plan cases. The OUCC urges the Commission to consider and base their decision on the lack of transparency, the lack of a reconciliation mechanism for the shareholder incentive, deficient testimony, and problematic assumptions discussed below.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to recommend the Commission deny DEI's proposed DSM Plan for the following primary reason:

- The proposed DSM Plan and its underlying assumptions unjustifiably boost shareholder incentives through:

- Inflated avoided capacity costs;
- Inflated avoided energy costs;
- Incorrect benefit/cost test calculations; and
- DSM program assumptions concerning expected useful life and savings impacts that are overstated.

In addition to the aforementioned cost effectiveness issues, the OUCC recommends the following:

- Deny DEI's proposed shareholder incentives for the proposed Low Income Neighborhood and Outdoor Lighting Modernization programs;
- Deny DEI's request for lost revenue for the Outdoor Lighting Modernization program;
- Order an independent review of impact assumptions and calculations DEI uses in its DSMore and Utilities International software programs; and
- Approve the OUCC's proposed methodology for a new shareholder incentive that addresses the lost opportunity to invest in a supply-side resource.

I will address each of these topics in detail. I will also explain how the proposed new shareholder incentive mechanism can provide reasonable incentives to the utility and also complies with the Indiana Administrative Code ("IAC" or "Commission rules"), by reconciling the utility's savings estimate with what actually happens in the future. This will bring fairness to customers and accountability to the concept, which are missing in the current methodology.

Q: Please describe the review and analysis you conducted in order to prepare your testimony.

A: I reviewed DEI's Verified Petition, Direct Testimony and Exhibits submitted in this Cause. I attended and participated in DEI's DSM Oversight Board Meetings. I reviewed Evaluation, Measurement and Verification ("EM&V") reports. I met with DEI representatives on several occasions to discuss issues in this Cause. I also composed data requests ("DRs") and reviewed DEI's discovery responses.

Q: Are you sponsoring any attachments to your testimony in this proceeding?

A: Yes. I am sponsoring:

- Attachment JEH-1, which contains Petitioner's responses to selected OUCC DRs;
- Confidential Attachment JEH-1C, which contains Petitioner's confidential attachments in response to OUCC data requests;
- Attachment JEH-2, which is the 2001 California Standard Practice Manual;
- Attachment JEH-3, which is a spreadsheet example of the OUCC's recommended shareholder incentive mechanism;
- Attachment JEH-4, which is an excerpt from the Results of the 2018 Northwest Residential Lighting Long-Term Monitoring and Tracking Study;
- Attachment JEH-5, which is a summary of retail store offerings of desk lamps;
- Attachment JEH-6, which is an excerpt from the Uniform Methods Project Chapter 6 (Residential Lighting Evaluation Protocols), Section 4.4. The full chapter can be accessed at: https://www.nrel.gov/docs/fy17osti/68562.pdf

- Attachment JEH-7, which is an excerpt from Cause No. 45253, Testimony of DEI witness John A. Verderame, page 15, lines 3 and 4 of Petitioner's Exhibit 23.
- Attachment JEH-8, which is an email confirming the OUCC's interpretation of a data response; and
- Attachment JEH-9, which is a spreadsheet showing the Non-Residential A-Line bulb net present value ("NPV") analysis.

Q: To the extent you do not address a specific item or adjustment in this testimony, does this mean you agree with those portions of Petitioner's proposal?

A: No. Excluding any specific adjustments or amounts DEI proposes does not indicate my approval of those adjustments or amounts. Rather, the scope of my testimony is limited to the specific items addressed herein.

II. PROPOSED FOUR-YEAR PROGRAM

Q: In comparison to DEI's last approved Plan, what changes does DEI propose to its DSM programs in this Cause?

A: DEI has significantly decreased the amount of general service lighting ("GSL") LED light bulbs offered through the Residential Smart Saver program and increased the amounts of LED GSL bulbs in other programs such as the Multifamily Energy Efficiency Products and Services and Residential Energy Assessments programs. These latter programs yield a much higher shareholder incentive and no justification for the change is offered.[2] In addition, the Smart Saver Non-

[2] Attachment JEH-1, DEI response to OUCC DR 2.1, and Supplemental Response dated 01/23/2020.

Residential Incentive program budget and shareholder savings estimate significantly increased to $11.3 million out of the total portfolio estimate of $21.1 million.[3] DEI witness Amy B. Dean discusses DEI's proposed four-year Plan. While it appears the programs are continuations of the 2017-2019 DSM Plan, there are significant changes not discussed by Ms. Dean. Noteworthy changes from the 2019 plan include:

1. The Agency Assistance Portal program will cease providing packages of LED light bulbs to qualifying customers after 2020;[4]
2. The Energy Efficiency Education program will cease providing GSL A-Line LED bulbs in kits after June 30, 2020. Kits will include specialty LED bulbs;[5]
3. The budget for the Multifamily Energy Efficiency Products and Services program is proposed to increase from the 2019 level of $178,000 to approximately $2.7 million in 2020;
4. The budget for the Residential Energy Assessments program is proposed to increase from the 2019 level of $917,952 to $1,332,658 (a 45% increase) in 2020 and $1,524,727 in 2021;
5. The budget for the Residential Smart Saver program decreases by 48% from $8.66 million in 2019 to $4.5 million in 2020. In the Lighting portion of the program, GSL LED bulbs will not be offered through the On-Line Savings store

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[3] Testimony of Timothy J. Duff, page 9.

[4] Attachment JEH-1, Response to OUCC DR 3.1.

[5] Attachment JEH-1, Response to OUCC DR 1.19 and Attachment OUCC 2.6-A.

or through the Free Lighting programs after June 30, 2020. GSL LED bulbs are proposed to continue through Retail Lighting program, but at a diminishing rate in each subsequent year.[6]

6. The budget for the Smart-Saver Non-Residential Incentive program increases from $9.4 million in 2019 to $12.6 million in 2020; and
7. A new program, the Outdoor Lighting Modernization program, has been added.

Q: How were these changes in DEI's DSM Plan offering communicated to the OUCC?

A: The OUCC learned of these changes through the post-filing discovery process. These changes, other than the introduction of the new Outdoor Lighting Modernization program, were not discussed in DEI's case-in-chief nor disclosed in the Oversight Board meetings. As stated in the Commission's recent order in Cause No. 44340 FMCA 12, page 11:

> We remind NIPSCO that as the petitioning party, its case-in-chief must include sufficient detail to support its requested relief in order to carry its evidentiary burden. As our recent orders in the City of Evansville and Indiana-American Water Company cases reiterate, when a petitioning party fails to provide basic supporting information in its direct evidence and does so only in discovery or rebuttal testimony, time and resources are needlessly wasted.

Without this OUCC testimony, the evidentiary record would hold little substantive detail of the DSM Plan for which DEI seeks approval.

Q: What concerns does the OUCC have with DEI's proposed programs in this proceeding?

A: The OUCC is concerned with the cost effectiveness of the programs. Specifically,

[6] Attachment JEH-1, Response to OUCC DR 1.19.

the OUCC is concerned about the measure impact assumptions, avoided cost inputs, and the calculation methodology DEI uses for the benefit/cost tests, which all drive shareholder incentives. In addition, the OUCC is concerned with the continued assumption of halogen lighting as the baseline for GSL LED lighting measures for the next 12 years. As discussed in depth later, these methods and assumptions overstate the cost effectiveness and, consequently, the shareholder incentives DEI will realize over the next four years are inflated.

Q: How does DEI's estimate of shareholder incentives compare to the other Indiana investor owned utilities ("IOU")?

A: DEI's estimate of the shareholder incentive for the four-year period is $21.1 million or, an average of $5.3 million per year. The other IOUs have estimated or actual shareholder incentives as follows:

- Indianapolis Power & Light Company: $5.3 million over 3 years, or $1.77 million/year average;
- Indiana Michigan Power: $1.73 million over 3 years, or $0.581 million/year average;
- Vectren Energy Delivery: $1.56 million/year average; and
- Northern Indiana Public Service Company: $1.71 million/year average.
- Total Combined Yearly Average (for the remaining four Non-DEI IOUs): $5.62 million/year.

DEI is the largest electric utility in Indiana; however, DEI's estimated shareholder incentive is disproportionally higher than that of the other utilities, as shown below, due to the aggregate effects of its overstated estimates and assumptions used to calculate the Utility Cost Test ("UCT").

Company	Customer Count	Percentage of Total
Duke Energy Indiana	840,000	34.74%
Indiana Michigan Power	468,000	19.35%
Indianapolis Power & Light	500,000	20.68%
NIPSCO (Electric)	468,000	19.35%
Vectren (Electric)	142,000	5.87%
Total	2,418,000	

It should also be noted that DEI's estimate of shareholder incentives for the 2017-2019 period was originally $10,950,352,[7] or approximately half of what DEI is actually recovering for this same period[8] and projects to recover in its proposed Plan.[9]

Q: Other than the residential LED GSL lighting issue already mentioned, what other concerns do you have with measure assumptions DEI uses?

A: DEI has individual cost and impact studies it assigns for a large number of measures. I examined the following measures and found problems with each one:

- Non-residential LED GSL;
- Portable desk lamp;
- School Kits; and
- GSL LED lighting baseline.

[7] Cause No 43955 DSM 4, Testimony of Michael Goldenberg, page 30.

[8] See Cause No. 43955 DSM 6, Exhibit 2-B (DLD), page 2, and Cause No. 43955 DSM 7 Exhibit 2-B (KCL), pages 1 and 2.

[9] Confidential Workpaper 1 (KKH) page 2.

The full discussion of these measures is contained in Appendix B to my testimony. It is likely there are many more issues with other measures. Therefore, the OUCC recommends an independent review of impact assumptions DEI uses in its DSMore and Utilities International software programs. Duke Energy corporate staff runs these programs and is responsible for the assumptions used therein. The modeling methods, assumptions, and calculations are not subject to independent review. As a result, there is no transparency and the modeling results cannot be replicated or verified by any other party, including the IURC, which needs to justify DEI's assumptions and evidence documented in its CIC in order to make a ruling in this case.

Q: What recommendations are the OUCC making concerning approval of the proposed programs?

A: The OUCC recommends denial of the programs until the measure impact assumptions are reviewed by an independent third party and the benefit/cost tests are calculated properly using correct avoided cost estimates. Given the multiple issues in all aspects of DEI's estimates and calculations, the cost effectiveness of individual programs and the portfolio cannot be ascertained at this time.

Q: What concerns does the OUCC have with DEI's proposed C/I programs?

A: Technologies are improving and costs are rapidly decreasing in this sector. Consequently, customer incentive levels must be monitored closely to minimize free ridership and its direct adverse effect on cost effectiveness. Often, past utility practice was to run programs for a year or more, spend a year performing an evaluation of what happened and finally make a report with possible recommended changes. This is not a sufficient timeline nor prudent expectation in view of the rapid changes in market pricing and technologies, especially for the C/I programs. As an example, I discuss in depth in Appendix B issues identified with the Non-Residential Smart Saver A-Line LED bulb measure. Unlike other IOUs, DEI does not evaluate all programs on an annual basis and therefore the OUCC recommends continued diligence in administering these programs cost effectively and more frequent re-evaluation of measures when prices and efficiencies change significantly.

III. PROGRAM COST EFFECTIVENESS

Q: What makes a DSM program cost effective?

A: The concept of DSM cost effectiveness is simple. In general, utility-sponsored DSM seeks to influence customers' demand or consumption of electricity such that the cost of doing so is more economic than meeting customers' needs through supply-side resources. This means the production of energy by supply-side resources may be reduced and the construction or acquisition of supply-side resources may be delayed or reduced.

Q: How is the appropriate level of DSM determined?

A: The appropriate economic level is determined in the Integrated Resource Planning ("IRP") process. Specific DSM programs or individual measures are seldom modeled in the IRP process due to the volume of variables that would need to be considered. Instead, programs are grouped into incremental bundles and are modeled as resources that can be selected in the IRP modeling process.

Various levels of DSM impacts and costs are modeled in conjunction with supply-side resources to find the most economic combination over the planning period. These analyses are distilled down to net present value of revenue requirements ("NPVRR") necessary over various scenarios and sensitivities. In the course of IRP modeling, DSM resources may be selected to the extent they contribute to a lower NPVRR. If some levels of DSM are not selected in the near term, it may mean they are not needed due to:

- Existing excess supply-side capacity;
- The life of the DSM measure is relatively short;
- The cost of delivering certain bundles of DSM is too high; or
- Other supply-side resources are more cost effective.

Q: How are the benefits of DSM quantified?

A: There are generally two sources of value derived from DSM programs. First, the variable production cost of energy is avoided by the amount of energy the programs save. This savings in the avoided cost of producing energy begins immediately. Second, to the extent DSM programs cumulatively represent a reduction in supply-side capacity requirements, there is a savings in delaying (time value of money) or reducing investment in additional capacity resources. However, this value is dependent on the timing of the need for additional capacity resources. Capacity values for DSM resources are acquired and paid for over longer periods than supply-side alternatives because the rate at which savings are cumulatively realized through DSM is generally slower and smaller. This means future avoided capacity costs derived from DSM resources are essentially being pre-paid for a period of time before they may actually be needed. If the saved energy and accumulation of demand reduction is cost effective, the IRP modeling will select the appropriate amount of DSM bundles.

Q: How should these concepts of cost effectiveness be applied to individual DSM programs?

A: The concepts are the same, but the methodology is different. Instead of seeking a combination of resources that yields a minimized NPVRR, as done in the IRP analysis, the programs and sometimes the individual measures are evaluated by comparing their costs over time to their benefits on an NPV basis. Costs are defined as the direct and indirect costs of the programs inclusive of EM&V costs and shareholder incentives.[10] Benefits are the future savings in the variable cost of energy avoided through decreases in customer consumption plus the present value of capacity discounted from the time a supply-side resource would otherwise be needed. This is consistent with IRP modeling which discounts the cash flow necessary to construct or acquire a supply-side resource from the time those costs are incurred to the present period in the NPVRR analysis. A formula demonstrating the <u>concept</u> of discounting the value of capacity from the time it is needed to the present appears in 170 IAC 4-4.1-9 (b). Not doing so would be analogous to constructing a supply-side resource years before it is needed and ignoring the time value of money used earlier than necessary.

It is also important to note the "avoided costs" used in this analysis are not outputs of the IRP analysis, but rather are inputs to the IRP process based upon estimates made by the utility. These are the same estimates of costs used to screen

[10] 170 IAC 4-8-1 (n)

DSM bundles in the IRP. "Avoided costs" are considered benefits and the UCT can be considered the foundation of the four basic benefit/cost tests. The other cost tests add or subtract other costs such as customer incentives and lost revenues to gain a perspective of benefits and costs from the viewpoints of other stakeholders such as DSM program participants, non-participating customers, and society, as defined by the Total Resource Cost Test ("TRC").

Q: Do DEI's benefit/cost analyses adhere to this methodology?

A: No, not entirely. The general <u>method</u> DEI used to model energy savings is correct; however, the benefits of avoided capacity are not modeled correctly. The prices of supply-side generating capacity in each year, should it be acquired, are estimated by DEI and listed.[11] DEI assumed the amount of demand reduction from DSM efforts in any year are multiplied by the listed price of capacity in that first year and by the listed price of capacity in subsequent years for the life of the measure/program. There is no consideration given to when capacity costs are actually avoided. This is an incorrect calculation and is inconsistent with the IRP analyses, which are discounted cash flow calculations. On page 23 of the 2001 California Standard Practice Manual ("CSPM"),[12] benefits under the Program Administrator Cost Test, also known as the UCT, are defined as:

> The benefits of the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction of transmission, distribution, generation, and capacity valued at marginal costs for the period when there is a load reduction.

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[11] Attachment JEH-1, Confidential response to OUCC DR 1.1, Attachment 1.1-A.

[12] Attachment JEH-2.

The key words are "avoided supply costs." In terms of generating capacity for DEI, the avoided capacity costs will not begin until 2023 or later, despite there being a demand reduction due to DSM efforts in 2020 through 2024. The second part of the sentence, "…valued at the marginal costs for the period when there is a load reduction" refers to that period when capacity is needed, but reduced by DSM (2023 and thereafter in this case) for the life of the measure or program. It is a common error to rely on the last part of the definition and ignore the important first part containing the key word "avoided." Moving to page 25 of the CSPM, the formula for benefits, B_{pa}, uses the summation of <u>avoided</u> costs, UAC_t, discounted to the present (2020 in this case):

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t+1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

The appropriate UAC_t values for years t=0 (2020) through t=3 (2022) should be zero for each year because zero capacity needs times the price of capacity equals zero. Beginning in t=4 (2023), and thereafter through the life of the measure or program, the formula is used to calculate the present value of the future benefits of avoided capacity. For example, if the DSM measure or program has an expected life of 10 years, the formula on page 25 for B_{pa} relative to capacity should be used to calculate the benefits for t=4 through t=10, which is the summation of the demand reduction in each year times the price of capacity in each year, discounted to the present. The second summation term of the formula applies to alternate fuels and does not apply to this discussion.

Q: Does the OUCC have any other concerns with DEI's benefit/cost calculations?

A: Yes. The calculations for the Ratepayer Impact Measure ("RIM") Test and the TRC Test are not correct. As can be seen in Petitioner's Workpaper 1 (JPW), DEI omitted the shareholder incentive from the calculations. The estimates for the shareholder incentives are shown on Petitioner's Confidential Workpaper 1 (KKH), page 2 under the heading, "Shared Savings Incentive." Shareholder incentives are defined as energy efficiency program costs by 170 IAC 4-8-1 (n). The words, "shareholder incentive" do not appear in the 2001 CSPM – most likely because shareholder incentives were rare at that time. Regardless, the general concepts of the tests require their inclusion in the TRC and RIM tests. The definition of the RIM test is:

> The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.[13]

Shareholder incentives increase customer bills. Therefore, it is appropriate to include this customer cost in the RIM test. Similarly, the following definition appears for the TRC test at page 18:

> The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

[13] California Standard Practice Manual, page 13.

Shareholder incentives are not included in the UCT because they are not costs to the utility.

Q: Has the Commission addressed the issue of including all costs in the benefit/cost tests where appropriate?

A: Yes, on page 46 of Commission Order in Cause No. 43955 DSM-3:

> The OUCC took issue with several of Petitioner's proposed programs. First, the OUCC argued that Petitioner's TRC calculation methodology is flawed. Second, the OUCC argued that Petitioner's Appliance Recycling Program is not likely to succeed as designed. Finally, the OUCC argued that Petitioner's Weatherization Program provides little program detail and is designed to place all risk on ratepayers. With regard to Petitioner's TRC calculation, OUCC witness Paronish argues that Petitioner is incorrectly excluding certain costs from the TRC calculations, artificially making the results look more favorable. The OUCC argues that Petitioner is improperly choosing to classify some items as customer incentives rather than program costs. In rebuttal testimony, Petitioner admits they calculate the TRC for all programs with equipment provided for free to the customer categorized as an incentive. Petitioner also acknowledges that the TRC results would be lower if all equipment costs are included. Petitioner did provide revised TRC results for the affected programs. All individual programs, with the exception of the Low Income Weatherization program, still pass the TRC, and the overall portfolio of programs also still passes the TRC test. It should be noted the Weatherization program did pass the initial TRC test. We agree with the OUCC that all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and ***administration costs, no matter who pays for them, should be included in this test.*** (Emphasis added)

Q: Does the OUCC have a concern with the cost effectiveness calculations for the Outdoor Lighting Modernization program?

A: Yes. DEI's benefit/cost test calculations relating to the Outdoor Lighting Modernization program do not include all the direct costs. DEI included only "incremental" costs.[14] DEI defined the incremental cost to be the full installed cost of the LED fixture minus the cost of the baseline High Intensity Discharge ("HID") fixture.

The use of "incremental" costs in this instance is misplaced. DEI's position implies the HID fixture would be replaced in kind and the LED fixture is an upgrade. This would only be true if the existing HID fixture had failed and needed to be replaced. That is not the case here. This program is for the replacement of working HID lamps and fixtures that will be retired and replaced by LED fixtures. A simple analogy is the replacement of a working CFL bulb with an LED bulb in a table lamp at home. The new LED bulb costs a dollar and there is an expectation of savings due to the more efficient bulb. The cost to make this change was one dollar, not the dollar paid minus the cost of a new CFL (considered by DEI to be the "incremental" cost). The full direct and indirect costs should be applied to the benefit/cost tests. The OUCC recommends the Commission direct DEI to calculate the benefit/cost tests for this program correctly by including all the costs.

Q: Does the OUCC have concerns with the proposed shared savings financial incentive proposed by DEI for the Outdoor Lighting program?

A: Yes. It is inappropriate to award a shareholder incentive for this program because shareholders will also earn a return of and on the investments in the measures. These lights will be offered under DEI's outdoor lighting tariffs and Rider 42. DEI Witness Amy B. Dean stated in her direct testimony:

[14] Attachment JEH-1, response to OUCC DR 4.7.

> After seeing a company-owned asset program had been approved for another Indiana utility in 2018, Duke Energy Indiana started to investigate its own offering.[15]

Since I&M is the only other Indiana IOU that has a street lighting DSM program, the OUCC assumes she is referring to I&M's Public Efficient Streetlighting program, for which I&M recovers neither lost revenues nor a shareholder incentive. The OUCC recommends denial of shareholder incentives and lost revenues for this program, consistent with I&M's rate treatment. OUCC Witness Caleb Loveman discusses the accounting treatment recommended for this program.

Q: Does the OUCC have concerns with the proposed shared savings financial incentive proposed by DEI for the Low Income Neighborhood program?

A: Yes. DEI has offered the Low Income Weatherization program and the Low Income Neighborhood program for years and has not required a shareholder incentive to do so. DEI witness Timothy J. Duff states:

> By including this important program in the portfolio, the Company believes it should have an opportunity to earn a reasonable financial incentive to offset financial bias against this particular program.[16]

DEI is proposing it be awarded a shareholder incentive based upon an estimation of the present value ("PV") of avoided costs without considering any direct or indirect costs of the program. The Commission rules prohibit this in two places. At 170 IAC 4-8-3 (c) states:

> The commission shall not approve financial incentives for a home energy assistance program that is not cost effective.

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[15] DEI Witness Amy B. Dean, page 4, line 13 through Page 5, line 2.

[16] Testimony of Timothy J. Duff, page 17, lines 13-15.

And, at 170 IAC 4-8-7 (e):

> A financial incentive must reflect the value to the utility's customers of the supply-side resource avoided or deferred by the utility's energy efficiency program or demand response program minus the incurred utility program costs.

By ignoring the program's costs in the PV calculation, DEI clearly does not meet either standard.

Q: Does the OUCC have a recommendation concerning cost effectiveness calculations?

A: Yes. The Commission should require DEI to recalculate the benefit/cost tests using the correct treatment of avoided capacity costs. Given DEI is requesting the UCT be used as the basis for shareholder incentives, it is imperative the inputs be correct and the math performed accurately.

IV. AVOIDED COSTS

Q: Does the OUCC have concerns with the avoided energy and capacity costs used by DEI?

A: Yes. The OUCC has concerns with both avoided energy costs and avoided capacity costs DEI used in calculating the benefit/cost tests, especially the UCT.[17]

Regarding the avoided energy costs, DEI included a carbon tax in its avoided cost calculations.[18] Inclusion of carbon taxes in the energy costs of fossil fueled generation is simply a modeling device used in IRPs to quantify scenarios representing possible carbon legislation. However, inclusion of a carbon tax in energy costs when calculating benefit/cost tests is inappropriate because this cost does not exist. There is no carbon tax or pending legislation to that effect. If there

[17] Attachment JEH-1, Confidential responses to OUCC DR 1.1 and 1.2.

[18] Attachment JEH-1, response to OUCC DR 4.10.

were such a tax, it would apply to carbon emissions and not to all avoided energy production. The effect of including a carbon tax in this context is to artificially inflate the NPV of benefits under the UCT and, consequently, the shareholder incentives benefits, by avoiding a pseudo cost.

Q: What are the OUCC's issues with DEI's avoided capacity costs?

A: On this topic, the OUCC's concern is the excessive amount of avoided transmission and distribution ("T&D") capacity costs DEI used. T&D capacity benefits are created when DSM programs alleviate capacity issues on specific circuits. None of DEI's DSM programs target specific circuits.

Certain circuits are being addressed though the Integrated Volt-Var Control Program ("IVVC"), which DEI is implementing as part of its $1.4 billion TDSIC Plan pursuant to Cause No. 44720. DEI's TDSIC Plan projects will impact both current and future T&D capacity issues. DSM programs cannot take credit for benefits obtained through TDSIC projects. In view of the likelihood the seven-year TDSIC Plan will be completed prior to DEI needing additional generating capacity in 2023, the "avoided" T&D costs due to DSM should be set to zero in the UCT calculation for this Cause.

In addition, DEI's values for avoided T&D capacity costs are not reasonable. As shown in the response to OUCC DR 1.4,[19] avoided T&D capacity costs are based upon a 2016 calculation of the average cost of DEI T&D projects from 2008 to 2015. DEI represents these projects were undertaken to address

[19] Attachment JEH-1 response to OUCC DR 1.2.

growth in customer load. DEI divided these costs by expected growth in peak load. This results in "avoided" T&D capacity cost per kW estimates, which DEI escalated to 2020. For 2020, these estimated avoided costs are 102% of estimated generation capacity.[20] When the OUCC's concern with this methodology was voiced in the DSM-7 case, DEI witness Karen K. Holbrook explained in her rebuttal testimony:

> The Company's methodology to determine the value of avoided T&D is based on a system average spending associated with investments to accommodate load growth divided by expected load growth. It is reasonable to assume that customers adopt DSM programs across the system in a manner that will result in load reduction across all circuits, including those with and without immediate capacity concerns. Therefore, by utilizing a calculation that is an average across the system, it can be relied upon to be reflective of the adoption of DSM programs.[21]

However, the flaws with this methodology are:

- There is no connection between circuit load reductions due to DSM and average construction expenditures made in the 2008-2015 time period (the basis of the referenced 2016 study[22]). Such projects often involve components unrelated to capacity such as poles, service transformers and system controls. The cost to construct facilities to serve new load has no relationship to the reduction in load spread over the DEI system. DEI has made gross assumptions unsupported by any evidence. The fact DEI expended capital costs to extend service to a new load, such as a new

[20] Attachment JEH-1, Response to OUCC DR 1.1, Attachment OUCC 1.1-A.

[21] Rebuttal testimony of Karen K. Holbrook, Cause No 43955 DSM-7, page 5, lines 16-22.

[22] Attachment JEH-1, Response to OUCC DR 1.2, Attachment OUCC DR 1.2-A.

residential subdivision or a shopping center, has no connection to DSM activities instituted elsewhere in the system.

- Despite delivering DSM programs for approximately thirty years, DEI has no evidence to support its assumptions concerning any relationship between DSM and avoided T&D costs. DEI has not put forth any evidence there are any circuits at capacity. Furthermore, it is stated at 170 IAC 4-8-7 (c):

> A financial incentive shall not provide an incentive payment for an energy efficiency program or demand response program unless the net kilowatt or kilowatt-hour impact, or both, can be reasonably determined.

DEI has not met this requirement. The financial incentive, discussed in more detail below, depends directly on the magnitude of T&D avoided costs.

- Far exceeding the effects of energy efficiency programs on the DEI system was the Great Recession that commenced in 2008. DEI's weather normalized summer demand dropped from 6,705 MW in 2007[23] to 6,493 MW in 2008 and to 5,988 MW in 2017. Energy dropped a similar pro rata amount from 33,747 GWH to 31,676 GWH over the same period.[24]
- Compared to other jurisdictional utilities in Indiana, DEI's avoided estimate of T&D avoided capacity cost is unreasonably large. The other utilities use estimates of zero to 40% of avoided generation capacity costs. DEI's

[23] DEI 2015 IRP page 205.

[24] Petitioner's Exhibit 3-A (DEI 2019 Integrated Resource Plan), page 113, Table B.2.

estimate is almost equal to 100% of its estimate of avoided generation capacity costs.[25]

- DEI is artificially inflating its total "avoided costs" by inflating the T&D avoided capacity cost component. This has the effect of approximately doubling its calculated shareholder incentive contributed by avoided capacity costs.

Q: Does the OUCC have a recommendation concerning treatment of avoided T&D capacity costs?

A: Yes. No two utilities use the same methodology in estimating avoided T&D capacity costs, and none provide any evidence quantifying a relationship between DSM and avoided T&D capacity costs. At best it is a theoretical concept that there are T&D capacity savings; however, no evidence has been offered that would satisfy the requirements of 170 IAC 4-8-7. Four of the five IOUs are involved in TDSIC programs which, aside from upgrading existing T&D systems, also include new construction designed to alleviate system capacity constraints. A common example is the replacement of 4KV distribution systems with 12 or 13.2 KV systems which are, of course, sized to satisfy current and anticipated capacity needs. For these reasons, the OUCC recommends avoided T&D capacity costs be set to zero, subject to actual evidence presented by the utilities or by a standard methodology established by the Commission.

[25] Attachment JEH-1, Confidential response to OUCC DR 1.1, OUCC Attachment OUCC 1.1-A.

Q: Does the OUCC have a recommendation concerning cost effectiveness calculations?

A: Yes. The Commission should require DEI to re-calculate the benefit/cost tests using the correct amounts and discounted treatment of avoided capacity costs. In view of the fact DEI is requesting the UCT be the basis for shareholder incentives, it is imperative the math be done accurately, correctly, transparently, and with reasonable estimates of future avoided costs.

V. SHAREHOLDER INCENTIVES

Q: What is the purpose of the financial incentives (sometimes called "shared savings") utilities may recover under IC 8-1-8.5-10?

A: "Shared savings" are financial incentives afforded utilities under IC 8-1-8.5-10 (g) (3) and (o). Utilities are awarded financial incentives to encourage implementation of cost effective DSM programs by offsetting the utility's regulatory or financial bias against DSM, or in favor of increasing load and constructing additional supply-side resources. Adding supply-side resources increases rate base, which in turn increases the amount the utility can earn on its investments. In theory, reducing demand for power through DSM programs will delay or reduce the need for new generation facilities, upon which the utility could otherwise recover a return of and on its investment.

Q: What formula for calculating the proposed shared savings financial incentive does DEI propose in this Cause?

A: The formula DEI proposes in this proceeding is the same as approved in DEI's previous 3-Year Plan case, Cause No. 43955 DSM 4.[26] As further explained on

[26] Walter, page 63, lines 21-23.

page 45 of the order in that case:

> Therefore, we find that Petitioner is authorized to recover performance incentives for each of its programs, as follows:

Performance Incentives	
Achievement Level (kWh)	Incentive Level (NPV of net benefits of UCT)
110%	10%
100-109.99	8%
90-99.99 %	7%
80-89.99 %	6%
75-79.99 %	5%
0-74.99 %	0%

The formula is a two-step process calculated for each DSM program. Attainment of a percentage of the gross kWh savings target for the portfolio is used to set a percentage value between 0% and 10%, which is then multiplied by the NPV of the UCT.

Q: What are the OUCC's concerns with DEI's UCT calculations?

A: There are five aspects of DEI's UCT calculations the Commission should consider:

1.) DEI applied the wrong values for avoided capacity costs in its calculations;

2.) Avoided T&D capacity costs estimates included in the calculations are excessive and instead should be zero;

3.) DEI uses an avoided energy cost stream inflated by the assumption of a carbon tax;[27]

[27] Attachment JEH-1, response to OUCC DR 4.11.

4.) DEI used unreasonable estimates of savings based upon hours of use of certain measures; and

5.) DEI's use of halogen bulbs as the baseline to project future energy and demand savings for an unreasonable period.

Q: What other concerns does the OUCC have with the proposed shareholder incentive?

A: There is no true-up of the shared savings approach adopted by all Indiana utilities and the methodology is not aligned with the issue as accurately or appropriately as it should be. The purpose of the shareholder incentive is stated in IC 8-1-8.5-10 (o):

> If the commission finds a plan submitted by an electricity supplier under subsection (h) to be reasonable, the commission shall allow the electricity supplier to recover or receive the following:
>
> (1) Reasonable financial incentives that:
>
> (A) Encourage implementation of cost effective energy efficiency programs; or
>
> (B) Eliminate or offset regulatory or financial bias:
>
> (i) Against energy efficiency programs;
>
> (ii) In favor of supply side resources.
>
> (2) Reasonable lost revenues.

Q: What are the fundamental shortcomings of DEI's proposed shareholder incentive?

A: The lost opportunity to invest in a supply-side resource can be characterized as the NPV of the lost return on equity ("ROE") on a future supply-side investment. However, the UCT captures far more than that, including <u>estimated</u> energy savings over long periods. The results are incentives that far exceed the PV of lost opportunity for ROE on a supply-side investment. Some DSM programs may have high energy savings and low capacity savings (e.g. an efficient lighting program), which could result in a positive UCT despite little or no capacity savings. In these cases, there are no lost opportunities to earn a return on investment in a supply-side capacity resource. Recovery of direct and indirect costs as well as lost revenues are handled separately, and the utility is kept whole for those costs.

The benefits associated with the UCT test are all estimates of future savings, which are inherently imprecise. These benefits are also based upon utility estimates of avoided costs that are the same estimates used in its IRP process. The utility-estimated avoided costs are seldom justified, vetted, nor actually "approved" by the Commission, since IRPs are not docketed, adversarial proceedings. There is a wide range of avoided costs, especially T&D avoided capacity costs mentioned earlier, which can range from zero to over 100% of avoided generating capacity costs and are also based on widely differing and inconsistent assumptions. In addition, avoided capacity costs are typically misapplied, as previously discussed. Avoided energy costs that include carbon taxes have already been discussed. All these assumptions result in overstated UCT scores and, therefore, overstated shareholder incentives. Utilities take these incentives up front for the full life of each measure, without ever reconciling utility estimates of avoided costs against actual future savings results throughout the multi-year useful life of the DSM measures. Under the methodology approved in past DSM cases for the electric IOUs, the utilities recover their shareholder incentive almost immediately and with absolute certainty. Customers are left hoping they will receive the remaining benefits the utility estimated will be saved over the projected remaining life of each DSM measure. None of these future benefits are actually paid to utility customers because they are "avoided" costs that will theoretically be realized through lower future rate increases over the next decades.

Q: Are there any reasons shareholder incentives should be reconciled to actual experience?

A: Yes. Shareholder incentives are included in the definition of DSM costs. As stated in 170 IAC 4-8-1 (n):

> "Energy efficiency program costs" means:
> Direct and indirect costs of energy efficiency programs;
> Costs associated with the EM&V of energy efficiency program results;
> Reasonable lost revenues; and
> Reasonable financial incentives.

In addition, 170 IAC 4-8-2 (b) states:

> (12) If an electricity supplier is using forecasted cost and energy savings for cost recovery purposes, it shall propose a mechanism to reconcile forecasted costs and energy savings with actual costs and energy savings.

And, at 170 IAC 4-8-7:

> (c) A financial incentive shall not provide an incentive payment for an energy efficiency program or demand response program unless the net kilowatt or kilowatt-hour impact, or both, can be reasonably determined.
> (e) A financial incentive must reflect the value to the utility's customers of the supply-side resource cost avoided or deferred by the utility's energy efficiency program or demand response program minus the incurred utility program costs.
> (g) A financial incentive may be based on forecasted demand reductions or energy savings until the information on demand reductions and energy savings from the utility's EM&V activities become available.

DEI proposes no mechanism to reconcile the avoided costs that are forecasted savings used in calculating the shareholder incentives estimated in this proceeding.

Q: Does the OUCC have a recommendation on this matter?

A: Yes. The OUCC recommends replacing the current UCT-based methodology with a more straightforward methodology that would directly address the lost opportunity to invest in a supply-side resource and be easier to administer. As explained below, the new methodology does not rely on imprecise estimates of avoided capacity and energy and reconciles the lost opportunity to invest in supply-side capacity with the actual timing of those costs. The new methodology avoids awarding incentives without a verified basis and is reconciled to actual costs as required by Commission rules.

Q: Please explain the OUCC's recommended methodology.

A: The calculation uses an enhanced ROE on the foregone supply-side investment discounted to the year the DSM measures are deployed. A portion of the ROE on the foregone supply-side investment attributable to the year the DSM measures are deployed, subject to EM&V of those measures or programs, would be awarded in the first reconciliation filing after the EM&V is completed. The remainder of the shareholder incentive would be awarded at the time the diminished (by DSM) or deferred supply-side resource is acquired. This would satisfy the requirements of 170 IAC 4-8-2 and the other rules noted above. This method removes the risks from both the utility shareholder and ratepayers.

Q: What does the OUCC recommend for the enhanced ROE and the percentage of initial reward?

A: The OUCC defers to the Commission to determine the appropriate percentages. However, the OUCC recommends an enhanced ROE of .5% greater than the ROE awarded the utility in its most recent general rate case and an initial award percentage of 30% of the enhanced ROE.

Q: What other issues does the OUCC's proposed shareholder incentive address?

A: The current UCT-based methodology contains a significant amount of savings from the NPV of saved energy. This, of course, has no relationship to the lost opportunity to earn a return on a future investment, which is influenced only by the need for capacity. In addition, the avoided cost of energy is an estimate and may contain adders such estimates of arbitrary future carbon taxes used in the IRP process. As used in IRPs, carbon taxes are a device used by models as a proxy for possible carbon legislation. It would be inappropriate to award shareholders a percentage of the present value of avoided proxy carbon costs. It is also prohibited by 170 IAC 4-8-2 (b) and 170 IAC 4-8-7 (c).

Q: Please provide an example of how the calculation might work.

A: Certainly. Variables used in the calculation will be unique to each utility, but readily available to the utility. For this example, the variables are assumed to be:

1. DSM in year 1 achieves 10 MW of net demand impact;
2. Expected average life of measures = 10 years, none less than 5 years;
3. Return on Equity ("ROE") = 9.5%;
4. Enhanced ROE = 10.0%;
5. Capital structure is 50% equity;
6. Discount rate = 7% (Weighted Average Cost of Capital);
7. Capacity acquired at year end 4 (as per the IRP) at $1,000/kW. For simplicity, this is also the actual cost of capacity incurred at the end of year 4;

8. In year 5, the foregone ROE = $1,000/kW (capacity cost) x 1,000 kW/MW (converting) x 10 MW (demand impact) x 50% (% of equity) x 10.0% (ROE) =$500,000;
9. In year 6, the investment to which the ROE is applied would be reduced by depreciation of the supply-side resource (30-year life);
10. There is no avoided cost savings after year 10 because that is the end of the EUL of the DSM measure/program;
11. 30% of foregone ROE paid out in year 1 (discounted from year 5) = $485,397;
12. Year 5-10 ROE reduced by 30% in each year.

See Attachment JEH-3 for a spreadsheet demonstrating the calculations. Please note the example is for only one year of DSM implementation. Subsequent years of DSM implementation would be additive to the example. The overall concept is to calculate the present value ("PV") of the ROE of the lost opportunity to invest in a supply-side resource, enhance the currently approved ROE, and multiply the enhanced ROE by the depreciated amount of the lost opportunity. Thirty percent (30%) of this value would be awarded in year one. The remaining seventy percent (70%) would be recovered beginning the year in which additional supply-side capacity is needed and reconciled to actual costs.

As shown on the spreadsheet, the PV of the lost ROE is $1,537,090. With the enhanced ROE and advancing 30% of the lost ROE, the PV of the shareholder incentive increases to $1,697,271 from the non-enhanced amount.

Q: Please explain your issues with the avoided capacity costs DEI used to calculate the UCT.

A: Avoided capacity costs should only be considered avoidable when there is a planning reserve margin deficit that would otherwise need to be met through a new capacity resource. Currently, DEI has a capacity surplus, and is unlikely to need additional capacity until 2023.[28] In addition, DEI will have an additional 100 MW of capacity available in 2021, which is currently under contract to another Indiana utility. [29] If made available to customers, this capacity could further delay the need for additional generating capacity beyond 2023.

VI. RECOMMENDATIONS

Q: Please summarize the OUCC's recommendations.

A: The OUCC recommends the Commission:

1. Deny DEI's shared savings recovery request until DEI recalculates the UCT scores and shared savings amount using revised *avoided* costs properly applied;
2. Deny DEI's proposed shareholder incentives for the proposed Low Income Neighborhood and Outdoor Lighting Modernization programs;
3. Deny DEI's request for lost revenue for the Outdoor Lighting Modernization program;
4. Order an independent review of impact assumptions DEI uses in its DSMore and Utilities International software programs;
5. Approve the OUCC's proposed methodology for a new shareholder incentive that addresses the lost opportunity to invest in a supply-side resource; and

[28] DEI 2018 Final Integrated Resource Plan, Volume 1, page 20. Table I.1.

[29] Attachment JEH-7, excerpt from Cause No. 45253, Testimony of DEI witness John A. Verderame, page 15, lines 3 and 4 of Petitioner's Exhibit 23.

6. Establish January 1, 2021 as the effective date for considering LEDs as the baseline for programs containing GSL.

Q: Are these recommendations reflected in OUCC witness Caleb Loveman's testimony?

A: No. Mr. Loveman's testimony reflects only his review of the accounting procedures and calculations DEI presented. The OUCC does not have the ability to run adjustments I recommend through the DSMore model to determine the NPV of benefits according to the UCT. Therefore, the OUCC cannot recalculate the proposed DSM Adjustment factors with any precision. The OUCC requests the opportunity to actively participate in the recalculation of the DSM Adjustment factors and to review and comment on the results prior to DEI submitting them to the Commission.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A TO TESTIMONY OF
OUCC WITNESS JOHN E. HASELDEN

Q: Please describe your educational background.

A: I am a graduate of Purdue University with a Bachelor of Science degree in Civil Engineering**.** I am also a graduate of Indiana University with the degree of Master of Business Administration, majoring in Finance. I am a registered Professional Engineer in the State of Indiana. I have attended and presented at numerous seminars and conferences on topics related to demand-side management ("DSM") and renewable energy.

Q: Please describe your utility business experience.

A: I began employment with Indianapolis Power & Light Company ("IPL") in April, 1982 as a Design Project Engineer in the Mechanical-Civil Design Engineering Department. I was responsible for a wide variety of power plant projects from budget and cost estimation through the preparation of drawings, specifications, purchasing and construction supervision.

In 1987, I became a Senior Engineer in the Power Production Planning Department. I was responsible for assisting and conducting studies concerning future generation resources, economic evaluations, and other studies.

In 1989, I was promoted to Division Supervisor of Fuel Supply and in 1990, became Director of Fuel Supply. I was responsible for the procurement of the various fuels used at IPL's generating stations.

In 1993, I became Director of Demand-Side Management. I was responsible for the development, research, implementation, monitoring, and evaluation of all marketing and DSM programs. In particular, I was responsible for the start-up of this new department and for the start-up and implementation of the DSM programs approved by the Commission in its Order in Cause 39672 dated September 8, 1993. The DSM Department was dissolved at IPL in 1997 and I left the company.

From 1997 until May, 2006, I held the positions of Director of Marketing and later, Director of Industrial Development and Engineering Services at The Indiana Rail Road Company. I was responsible for the negotiation of coal transportation contracts with several electric utilities, supervision of the Maintenance-of-Way and Communications and Signals departments, project engineering, and development of large capital projects.

I rejoined IPL in May, 2006 as a Principal Engineer in the Regulatory Affairs Department. I was responsible for the evaluation and economic analysis of DSM programs and assisted in the planning and evaluation of environmental compliance options and procurement of renewable resources.

In May, 2018, I joined the OUCC as a Senior Utility Analyst - Engineer. I review and analyze utilities' requests and file recommendations on behalf of consumers in utility proceedings. As applicable to a case, my duties may also include evaluating rate design and tariffs, examining books and records, inspecting facilities, and preparing various studies.

Q: What is your experience relative to Demand-Side Management?

A: As noted above, I was Director of DSM at IPL and when I rejoined IPL in 2006, I provided support for the DSM programs through conducting market potential studies and coordinating EM&V activities and analysis through 2017. I represented IPL on the Statewide Demand-Side Management Coordinating Committee ("DSMCC") from its inception in 2010 and also participated on the EM&V Subcommittee until the DSMCC disbanded after the passage of SEA 340 in 2014. Since joining the OUCC in 2018, I actively participate in DSM Oversight Board meetings and EM&V activities with all of the jurisdictional electric utilities.

Q: Have you previously testified before the Indiana Utility Regulatory Commission?

A: Yes. I have provided testimony in several proceedings on behalf of IPL regarding the subjects of Fuel Supply, DSM and renewable energy most recently in Cause Nos. 43485, 43623, 43960, 43740, 44328, 44018, and 44339. My testimony on DSM concentrated on the evaluation, measurement and verification ("EM&V") of DSM programs. My testimony on renewable energy concentrated on IPL's Rate REP (feed-in tariff, wind power purchase agreements and solar energy. I have provided testimony on behalf of the OUCC in Cause Nos. 43827 (DSM-8), 43955 (DSM-7), 43405 (DSM-17), 43623 (DSM-19), 45086, 45145, 45193, 45194, 45235, 45245, 45253, 44733(TDSIC-5) and 44910 (TDSIC-4).

APPENDIX B

Review of a Sample of DSM Measures Proposed by DEI

Non-residential LED GSL measure

This measure stood out because of the very high net present value ("NPV") of benefits attributed to it at $71.95/bulb.[1] Retaining 10% of this amount, DEI shareholders recover $7.20 for every bulb incentivized through the Smart Saver Non-Residential Incentive program.[2] Performance estimates for this measure are:

- 15 year life;
- Net-to Gross factor: 0.7325;
- Gross annual savings/measure (kWh): 113.258;
- Coincident summer peak savings (gross): 0.0238 kW; and
- Non-coincident summer demand savings (gross): 0.04417 kW.

To determine the annual hours of use of a bulb, divide the gross kWh/year by gross non-coincident demand savings:

113.258/.04417 = 2,564.1 hours/year.

Multiplying annual hours of usage by the expected life (2,564.1 hours/year x 15 years) yields the lifetime hours of bulb life equal to 38,462 hours. The problem here is an EnergyStar LED bulb has an expected life of between 15,000 and 25,000 hours.[3] DEI has overstated the hours of use and therefore the savings per bulb by approximately twice the physical life of a typical bulb for every bulb incentivized. Assuming a 25,000 hour bulb life, the bulb will last:

25,000hours/2,564 hours/year = 9.75 years.

DEI calculates this shareholder incentive to be $7.20/bulb.[4] However, it was noted DEI did not subtract the cost of the program to arrive at the NPV of benefits. The cost of the program per bulb in 2020 is estimated by DEI to be $17.78, as verified by DEI.[5] Making this adjustment yields a NPV of $4.52/bulb.[6] It is not known what costs are included in the $17.78/bulb other

[1] Attachment JEH-1, DEI response to OUCC DR 3.4

[2] Attachment JEH-1, DEI response to OUCC DR 2.1 (f) and OUCC DR 3.4.

[3] https://www.energystar.gov/products/lighting_fans/light_bulbs/key_product_criteria

[4] Attachment JEH-1, DEI response to OUCC DR 3.4 and 4.3.

[5] Attachment JEH- 8.

[6] Attachment JEH-9.

than the prescriptive rebate of $4.00/bulb.[7] This cost/bulb is not reasonable in view of the rebate incentive of $4.00 for a bulb that costs only $3-4. The OUCC is aware customers may have an additional labor cost to install the light bulb but that cost should not apply in this instance. At the annual hours of use calculated above, a customer would be changing out a baseline halogen bulb every nine months. Therefore, the change-out cost will occur (repeatedly) and this cost need not be considered when computing the incentive for the GSL LED bulb. In fact, by installing the LED bulb, the customer will avoid changing out the halogen bulb 12 times over the next 9.75 years. In view of these savings, in addition to saved energy, no customer incentive is necessary to induce the customer to make the correct economic choice.

Coupled with the other adjustments recommended for avoided costs and correct UCT calculations, the shareholder incentive for this measure should be $0.55/bulb, using a 10 year life of the measure.[8] If the two-year effective life is used as recommended by the OUCC, the shareholder incentive would be negative, or zero $/bulb.

<u>Portable LED Fixtures (Desk Lamp)</u>

DEI listed the following attributes of the portable desk lamp measure offered through the On-line store.[9] Attached is a description of the product taken from the DEI On-line Store:

- Customer incentive = $5.00
- Measure life = 20 years
- 0.003kW demand savings, 19.9 kWh annual savings, baseline Wattage = 31 Watts
- Fixture Wattage = 7 Watts
- Life of LED bulb – 50,000 hours

If the baseline Wattage is 31 Watts, the savings per hour are:

31Watts - 7Watts = 24 Watt-hours/hour, or 0.024 kWh/hour

If annual savings are 19.9 kWh/year, the lamp must be on:

19.9 kWh/0.024 kWh/hour = 829.2 hours/year. 829.2/365days/year = 2.3 hours/day

Check 20-year life: 2.3 hrs./day x 365 days/year x 20 years = 16,790 hours < 50,000 hours. OK

The reference for measure life of 20 years is from the 2016 Mid-Atlantic Technical Reference Manual Version 6.0, page 67[10]. The Mid-Atlantic Technical Reference Manual was recently

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[7] https://www.duke-energy.com/business/products/smartsaver/lighting

[8] Attachment JEH-

[9] Attachment JEH-1, response to OUCC DR 4.4.

[10] Attachment JEH-1, Response to DR 5.5

updated to Version 9.0. This section is applicable to Energy Star Integrated Screw Based Solid State Lighting LED Lamps. This section does not reference portable lamps or desktop lamps. The referenced section is intended for light fixtures installed in homes. The 20 year life was is a default value of the lifetime cap of 20 years. The savings assumptions are not known. When the source of the savings was requested in a data request, DEI responded the inputs were provided to DEI by Navigant.[11] No documents were provided to substantiate the estimated savings.

The OUCC has several issues with the savings assumptions and measure life:

1. The measure life reference (2016 Mid-Atlantic Technical Reference Manual Version 6.0, page 67) is outdated and does not apply to portable lamps. Such a lamp may have a life of 20 years but it cannot be counted upon for the fixture to remain in the residence 20 years. It is portable.
2. Although requested, there is no documentation or other evidence provided by DEI to substantiate the estimated savings.
3. There is no evidence to suggest this measure replaces older working desk lamps instead of simply a purchase by customers who need desk lamps.
4. There is no estimation of the installation rate of the measure. It appears from the savings assumptions that all of the lamps are installed in the home and none are given as gifts or sent away with family members to college.
5. The estimated baseline of 31 Watts implies an incandescent desk lamp would be purchased absent the LED desk lamp offering. I personally visited several retail stores (Target, Walmart, Meijer) and found half of the desk lamps for sale have integrated LED lamps.[12] Half of the lamps have medium base screw-in sockets but no lamps included except for one lamp that included an Edison-style amber incandescent bulb. No lamps included an integrated halogen or incandescent bulb. Similar to LED GSL lighting, this market has already transformed to LED as the baseline.

The OUCC recommends this DSM measure receive no lost revenues, shareholder incentive or cost recovery of customer incentives. There is no credible evidence provided by DEI to qualify it as a DSM measure.

Energy Education Program for Schools

Savings for this program have been driven by GSL LED bulbs contained in the Energy Efficiency Starter Kits. Beginning January 1, 2020, the bulbs in the kits will transition to two 5 Watt candelabra-base bulbs.[13] At this time, DEI assumes no change in the energy savings

[11] Attachment JEH-1, Response to OUCC DR 5.5 and 5.6.

[12] Attachment JEH-5.

[13] Attachment JEH-1, Response to OUCC DR 1.22 and 3.1.

associated with the new kits.[14] DEI quantifies savings in terms of the kit and does not break out the savings of components.[15] The next EM&V study for this program is unknown.

The installation rate for the candelabra bulbs can be expected to be very low because the percentage of available sockets is very low compared to typical medium base bulbs. Programs such as the Multi-Family Energy efficient Products program expect to install only about 10% as many candelabra bulbs as GSL bulbs.[16] Therefore, energy savings from this program can be expected to be significantly reduced from past years.

The OUCC recommends DEI make a revised estimate of savings for this program reflective of the significant reduction in savings attributed to the lighting measures. Thereafter, the benefit/cost tests for the program should be recalculated.

<u>General Service LED Bulbs</u>

Although the changes in DEI's DSM plan, in regards to GSL Lighting are not discussed in testimony, there is a strategy to reduce GSL bulbs in several programs but significantly increase their use in other programs – primarily in direct install programs. DEI is still clinging to the 12-year measure life, discussed below, for GSL LED bulbs. When coupled with high installation rates, shareholder incentives attributed to these programs are large. For example, DEI estimates the NPV of savings for a 9 Watt GSL LED bulb installed through the Multifamily Energy Efficiency program to be $19.16/bulb,[17] which yield a shareholder incentive of $1.916/bulb installed. DEI plans to install approximately 395,000 of these bulbs through 2023.

DEI credits savings for standard LED lights delivered through its DSM programs for the full 12 years of the assumed life of the LED bulb, as measured against a halogen bulb baseline. For example, a 9-Watt LED bulb is comparable to a 43-Watt halogen bulb, based upon lumen output. Using a halogen bulb as the baseline is an incorrect assumption based upon the significant changes in the lighting market for this measure. The standard GSL LED bulb will soon become, if it has not already, the baseline for this measure. Consequently, real savings attributed to GSL LED bulbs delivered through DSM programs will cease within the next few years due to this changed baseline.

In the context of DSM, a baseline is simply the type of measure a customer would choose absent a utility program incentivizing a more energy efficient choice.

The following list shows different factors influencing measure choice (i.e., choice of light bulbs):

1. Price;

[14] Attachment JEH-1, Response to OUCC DR 4.1

[15] Attachment JEH-1, Response to OUCC DR 1.15.

[16] Attachment JEH-1 Response to OUCC DR 2.6, Excerpt from Attachment 2.6-A.

[17] Attachment JEH-

2. Life of bulb;
3. Performance;
4. Warranty;
5. Warm-up time (in the case of CFL bulbs, there is often a delay in reaching full lumen output);
6. Waste heat (e.g., heat from lighting can increase air conditioning needs during warm weather);
7. Dimming (unless designed to do so, some LED or CFL bulbs are not capable of dimming or can only be dimmed within a limited range);
8. General appearance;
9. Size;
10. Shape;
11. Fit in fixtures; and
12. Color rendering.

GSL LED bulbs have evolved and improved to rate high in most of the above considerations, including price. The Northwest Energy Efficiency Alliance ("NEEA") recently published its annual "Results of the 2018 Northwest Residential Lighting Long-Term Monitoring and Tracking Study."[18] This study reports pricing, market share and retail stocking trends since 2012 for LED, CFL, halogen and incandescent lighting. This report also addresses stocking trends and how they correlate with sales levels of products. See page 31 of the report reproduced in Attachment JEH-4. The market has moved this direction, partly influenced by the impending backstop provisions of the Energy Independence and Security Act ("EISA") which was due to take effect January 1, 2020. In September 2019, the Department of Energy ("DOE") issued a Notice of Proposed Rulemaking ("NOPR") to rescind the Final Rule in the GSL matter. However, the bottom line is the market for GSLs has transformed, not only due to the threat of a government mandate, but also due to a real market transformation in which LED lamps have become the baseline due to both price and performance. Over the past year, I personally visited many retail stores to ascertain lighting stocks and pricing. I have observed that approximately 80-90% of shelf space for GSLs is occupied by LED bulbs, similar to the findings in the aforementioned NEEA report. Whether or when EISA rules are implemented has become irrelevant. Many retailers already made this change and price LED bulbs at or below the price of halogen bulbs (the current assumed baseline). The average customer is fully capable of making an informed economic choice to purchase LED lighting, regardless of what federal lighting standards might require.

Some LED bulbs in the market are not Energy Star bulbs and are sometimes called Value line bulbs. The packaging of these LED bulbs denote a 9-year life for the bulbs. Energy-Star bulbs usually have a longer life and cost more. The appropriate comparison for the Energy Star LED is the non-Energy Star LED and not the halogen bulb alternative. Unsubsidized, the non-Energy Star LED purchase price is competitive with a halogen equivalent and is far more cost effective

[18] Available at: https://neea.org/resources/results-of-the-2018-northwest-residential-lighting-long-term-monitoring-and-tracking-study

for customers in view of the fact a customer would need to purchase five halogens to obtain an equivalent life of a Value line LED, and additionally will obtain the benefits of nine years of significant energy savings. The non-Energy Star LED is far less expensive on a life-cycle basis. The fact that Energy-Star LED GSLs have an initial cost premium is relevant because the added energy savings for an Energy Star rated bulb do not begin for approximately 9 years. On a life-cycle basis, the Value line bulb is a better investment. The Uniform methods Project acknowledged this issue and recommended evaluators address the shift from non-Energy Star to Energy Star bulbs through the estimates of net-to gross. This means the baseline condition includes value line LEDs.[19]

However, it is financially advantageous for DEI to provide a DSM incentive for higher priced Energy Star LED bulbs for two reasons. The first reason is to increase the NPV of benefits of the UCT by extending the assumed saved energy and capacity for 12 years instead of 9 years. The second reason is because the pricing of the non-Energy Star GSL LED bulbs is already on par with halogen bulbs and there is no opportunity for a utility to intervene via price subsidization and subsequently claim energy and capacity savings. Therefore, recognizing the non-Energy Star LED GSL as the baseline means the utility would realize no shareholder incentive and no lost revenues. Recognizing this market change would cost DEI millions of dollars each year in shareholder incentives and lost revenues but save customers much more. DEI customers will additionally save on their bills by not having to pay for the direct costs of the Energy Star LED GSL bulb subsidies as well.

The OUCC recommends DEI use LEDs as the baseline bulb with a sunset date for market baseline transformation effective January 1, 2021. The benefit/cost tests should be recalculated using this information and the other recommended adjustments to avoided costs and methodology.

[19] Attachment JEH-6, Uniform Methods Project, Chapter 6 (Residential Lighting Evaluation Protocol), Section 4.4.

Public's Exhibit No. 1
Appendix B
Cause No. 43955 DSM 8
Page 7 of 9

Online Savings Store

1

Home / **tLight LED Black Desk Lamp**

More Views

ENERGY STAR

tLight LED Black Desk Lamp

Availability: In stock

Your Price: $16.98

Qty: 1 ADD TO CART

Add to Wishlist | Add to Compare

Details

The tLight Desk Lamp adds a touch of modern styling, and energy effiecent LED lighting to your home office, dorm room or kids room. With a 50,000 hour life, 365 degree swivel body, flexible neck and 7 watt output, you can count on the tLight desk lamp.

Key Features

50,000 Hour Life
7 watt
5 Year Warranty
Energy Star Rated

Specifications

PART #	N7700.102
MANUFACTURER MODEL	75353-BL
HEIGHT (INCHES)	No
WIDTH (INCHES)	5.9
DEPTH (INCHES)	5.9
LIGHTING TECHNOLOGY	No
FIXTURE TYPE	Portable
POWER CONSUMPTION (WATTS)	No
BRIGHTNESS (LUMENS)	No
COLOR RENDERING CATEGORY	Not Available
EFFICACY	85

(LUMENS/WATT)	
COLOR TEMPERATURE CATEGORY	No
RATED LIFE (HOURS)	No
ENERGY STAR CERTIFIED	No
DAMP/WET RATED	No
WARRANTY (YEARS)	5

Reviews ›

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Products offered to Duke Energy customers in Indiana have been selected through a competitive bidding process and are subject to change at Duke Energy's discretion. The prices in effect at the time an order is placed represents present pricing. Subsequent price changes cannot be retroactively applied to past purchases. We hope that you continue to visit the savings store to take advantage of discounted pricing to the products being offered.

Energy Federation, Inc. Southborough Massachusetts USA 877-627-9271 support_in1@efi.org

AFFIRMATION

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

John E. Haselden

John E. Haselden
Senior Utility Analyst
Indiana Office of Utility Consumer Counselor

Cause No. 43955 DSM-08
Duke Energy Indiana, LLC

3/2/2020
Date

Cause No. 43955 DSM-08

Duke Energy Indiana, LLC

Attachment JEH-1C

Confidential

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.1

Request:

Please provide the annual avoided capacity cost inputs used in the DSMore model for calculation of the UCT and TRC tests for the 2020-2023 DSM programs. Please also include a breakdown between generating capacity and T&D capacity.

Response:

Please see Attachment OUCC 1.1-A.

Attachment OUCC 1.1-A

CAUSE NO. 43955 DSM-8
OUCC Data Request Set No. 1
Q 1:1

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Avoided Capacity, $/KW-year	$ 70.65	$ 72.41	$ 74.22	$ 76.08	$ 77.98	$ 79.93	$ 81.93	$ 83.98	$ 86.08	$ 88.23	$ 90.43	$ 92.70	$ 95.01	$ 97.39	$ 99.82	$ 102.32	$ 104.88	$ 107.50	$ 110.19	$ 112.94	$ 115.76	$ 118.66	$ 121.62	$ 124.67	$ 127.78
Avoided T&D, $/KW-year	$ 71.90	$ 73.49	$ 75.14	$ 76.85	$ 78.64	$ 80.44	$ 82.27	$ 84.18	$ 86.12	$ 88.07	$ 90.03	$ 91.98	$ 93.95	$ 95.97	$ 98.02	$ 100.11	$ 102.26	$ 104.46	$ 106.71	$ 109.01	$ 111.40	$ 113.88	$ 116.43	$ 119.08	$ 121.90

090015419-000001

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.2

Request:

Please provide the workpapers supporting the avoided T&D capacity cost included above.

Response:

Please see Attachment OUCC 1.2-A.

DUKE ENERGY INDIANA, LLC
AVERAGE COST OF TRANSMISSION ADDITIONS
2016

Year	Load Growth Related Additions	% Summer Peak for Retail	Retail Load Growth Additions	HW Factor	Retail Load Growth Additions
			Nominal $		2016 $
	(a)	(b)	(c)	(d)	(e)
2009			$16,230,193	0.8957	$18,120,056
2010			$27,705,719	0.9130	$30,347,012
2011			$33,489,477	0.9464	$35,386,824
2012			$34,936,140	0.9618	$36,323,448
2013			$52,070,809	0.9813	$53,064,675
2014			$54,437,455	1.0000	$54,437,455
Average					$37,946,578
Average Annual Growth Related Expenditures			2016	1.0193	$38,680,144

Average Annual Growth Related Expenditures	$38,680,144
Projected Average Annual Growth	65,163
Cost per kW	$593.59
Annualized Cost per kW	$55.62
Monthly Cost per kW	$4.63

Note 1: Transmission is Accounts 350 to 358.

Note 2: Expenditures are inflated to 2016 $ using the Handy Whitman North Central Construction Cost Index for Transmission

DUKE ENERGY INDIANA, LLC
AVERAGE COST OF DISTRIBUTION ADDITIONS
2016

Year	Load Growth Related Additions		HW Factor	Retail Load Growth Additions
				2016 $
	(a)		(b)	(c)
2009	$11,912,708		0.8473	$14,058,861
2010	$3,302,004		0.8743	$3,776,902
2011	$3,079,878		0.9126	$3,374,800
2012	$5,905,886		0.9403	$6,281,084
2013	$8,792,730		0.9723	$9,042,807
2014	$7,000,119		1.0000	$7,000,119
Average				$5,895,142
Average Annual Growth Related Expenditures		2016	1.0202	$6,014,064

Average Annual Growth Related Expenditures	$6,014,064
Average Annual Growth	68,317
Cost per kW	$88.03
Annualized Cost per kW	$8.50
Monthly Cost per kW	$0.71

Note 1: Bulk distribution is Accounts 360 to 367.

Note 2: Expenditures are inflated to 2016 $ using the Handy Whitman North Central Construction Cost Index for Distribution

	A	B	C
1	DUKE ENERGY INDIANA, LLC		
2	SUMMARY OF FERC FIXED CHARGE METHOD		
3	COMPOSITE TRANSMISSION & DISTRIBUTION PLANT		
4	2016		
5			
6			
7		Component	Rate
8			
9	I.	Operating & Maintenance Expense	
10			
11	II.	Other Taxes	
12			
13	III.	Administrative & General Expense	
14			
15	IV.	Return	
16			
17	V.	Depreciation Expense/Replacement	
18			
19	VI.	Income Tax Expense	
20			
21	VII.	General Plant	
22			
23	VIII.	Accumulated Deferred Income Taxes	
24			
25	IX.	Working Capital	
26			Transmission
27		Annual Fixed Charge Rate	9.37%
28			
29		Monthly Rate	

DUKE ENERGY INDIANA, LLC
PROJECTIONS
2016

	Retail After EE MWH (a)	Retail Before EE MWH (b)	IRP Peaks After EE MW (c)	RETAIL Peaks Before EE MW (d)	Incremental MW (e) TRANS	Retail Customers (f)	Diversified Class MW (g)	Incremental MW (h) DIST
2016				5,742			6,008	
2017				5,821	79		6,091	83
2018				5,894	72		6,167	76
2019				5,954	61		6,230	64
2020				6,014	60		6,293	62
2021				6,081	67		6,363	70

Projected Average Annual Growth		68	71
Diversified Class Ratio (DCRatio)	1.05		
Loss Factors		3.81%	3.62%
Adjusted Projected Average Annual Growth at Customer Meter (w/o Losses)		65	68

Source: Summary 2014 Forecast.xlsx

Mnemonic (HNCR = North Central Region: ND, SD, NE, KS, MN, IA, MO, WI, IL, MI, IN, OI
FHWDPPP.HNCR
FHWTPPP.HNCR

Handy-Whitman Electric Plant Index Forecast	1980	1981	1982	1983	1984
Distribution Plant - Total Distribution Plant, (Index, 1973=100)	190	210	224	230	232.5
Transmission Plant - Total Transmission Plant, (Index, 1973=10	197.0	214.5	230.5	238.5	240.0

	2015	2016	2017	2018	2019
Distribution Plant - Total Distribution Plant, (Index, 1973=100)	678.5111	673.9103	692.9212	718.5049	739.3203
Transmission Plant - Total Transmission Plant, (Index, 1973=10	683.7	668.3	681.8	708.3	730.6
Average	681.1127	671.1125	687.342	713.3962	734.9695
Index 2016		1.000	1.024	1.063	1.095

1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
234.5	238.5	240	249.5	266	274	279.5	280	287.5	295	307
242.0	246.5	249.0	267.0	287.0	297.5	306.0	304.5	317.5	329.0	349.0

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
756.955	773.6657	790.582	808.3579	827.3123	846.0477	865.1599	885.314	905.6465	926.0557	946.6248
748.0	764.6	782.2	800.2	818.9	837.8	856.9	876.7	897.1	917.5	937.9
752.4989	769.1503	786.4033	804.3024	823.1162	841.9041	861.0308	881.0222	901.3554	921.7784	942.2757
1.121	1.146	1.172	1.198	1.226	1.254	1.283	1.313	1.343	1.374	1.404

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
313.5	315	323.5	325.5	330.5	342.5	355.5	368	382	412.5	456
355.5	361.0	372.5	370.5	382.0	401.0	411.5	417.5	440.5	478.0	520.0

2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
966.8721	987.3928	1,008.49	1,029.72	1,051.27	1,073.52	1,096.31	1,119.45	1,143.08	1,167.66	1,193.06
958.5	979.2	1000.4	1022.1	1044.4	1067.2	1090.4	1114.3	1138.9	1164.3	1190.7
962.6653	983.3053	1004.458	1025.917	1047.819	1070.337	1093.371	1116.899	1140.99	1165.983	1191.889
1.434	1.465	1.497	1.529	1.561	1.595	1.629	1.664	1.700	1.737	1.776

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
503	562.5	574	587	613.5	632	654	673	678.5111	673.9103	692.9212
560.7	617.0	615.5	618.0	640.5	649.5	666.5	676.5	683.7	668.3	681.8

2042	2043	2044	2045
1,219.40	1,246.83	1,276.12	1,307.19
1217.9	1245.8	1275.7	1307.4
1218.635	1246.328	1275.895	1307.313
1.816	1.857	1.901	1.948

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
718.5049	739.3203	756.955	773.6657	790.582	808.3579	827.3123	846.0477	865.1599	885.314	905.6465
708.3	730.6	748.0	764.6	782.2	800.2	818.9	837.8	856.9	876.7	897.1

2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
926.0557	946.6248	966.8721	987.3928	1,008.49	1,029.72	1,051.27	1,073.52	1,096.31	1,119.45	1,143.08
917.5	937.9	958.5	979.2	1000.4	1022.1	1044.4	1067.2	1090.4	1114.3	1138.9

2040	2041	2042	2043	2044	2045
1,167.66	1,193.06	1,219.40	1,246.83	1,276.12	1,307.19
1164.3	1190.7	1217.9	1245.8	1275.7	1307.4

Avoided T&D Used in DSMore
Year 1=2020

	Starting Point - 2016	2020	2021	2022	2023	2024	2025
Avoided T&D, $/KW-Year	$64.12	$71.90	$73.49	$75.14	$76.85	$78.64	$80.44

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
$82.27	$84.18	$86.12	$88.07	$90.03	$91.98	$93.95	$95.97	$98.02	$100.11	$102.26

2037	2038	2039	2040	2041	2042	2043	2044
$104.46	$106.71	$109.01	$111.40	$113.88	$116.43	$119.08	$121.90

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.3

Request:

Please provide the annual avoided energy cost inputs used in the DSMore model for calculation of the UCT and TRC tests for the 2020-2023 DSM programs. If a line loss factor is included, please provide the factor and the supporting analysis.

Response:

See Confidential Attachment OUCC 1.3-A.

A line loss factor of 7.43% was used in this proceeding. See Attachment OUCC 1.3-B from Cause No. 42359, where retail losses are calculated by dividing cell G21/H21.

Please note that this value represents the line loss from the view of losses from the generating plant to the customer's meter. For the purpose of line losses used in calculations in the DSMore software it is necessary to view the line loss from the perspective of the losses from the customer's meter to the plant, *i.e.* the amount of additional generation required to provide a given amount of KWh at the customer's meter. The formula for this conversion is $(1/(1-0.0743))-1 = 0.080264$

OUCC ATTACHMENT 1.3-B

VOLUME I
SCHEDULE G-1

PSI ENERGY, INC.

RETAIL COST OF SERVICE

ANALYSIS OF IMPA AND WVPA RESOURCE AND NON-FIRM TRANSACTIONS,
RETAIL METERING ADJUSTMENTS, LOSS CALCULATIONS AND
SYSTEM INPUT
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2002

KWH_SYS_INPT

A	B	C	D	E	F	G	H	I	K	L
DESCRIPTION	TOTAL COMPANY PRO FORMA (SALES BASIS INCLUDING UNBILLED)	NON-FIRM POWER	TRANSFER OF LOSSES	METERING ADJUSTMENTS	REVISED SYSTEM INPUT (METERED BASIS INCLUDING UNBILLED)	ALLOCATED LOSSES	SUB-TOTAL	ALLOCATION OF COMPANY USE	NON-FIRM POWER	PRO FORMA SYSTEM INPUT
RETAIL SALES	26,392,034,812	0	0	149,303	26,392,184,115	2,117,494,490	28,509,678,605	38,848,016	0	28,548,526,621
WHOLESALE SALES										
RATE MUN	244,959,200	0	0	0	244,959,200	13,828,506	258,787,706	352,631	0	259,140,337
LOGANSPORT	212,353,287	20,841,000	0	0	233,194,287	4,669,138	237,863,425	324,119	(20,841,000)	217,346,544
IMPA	1,327,793,186	1,518,172,877	(120,956,642)	0	2,725,009,421	104,704,801	2,829,714,222	3,855,842	(1,518,172,877)	1,315,397,187
WVPA	0	0	0	0	0	0	0	0	0	0
WVPA	536,178,577	1,909,442,641	(115,773,022)	0	2,329,848,196	97,528,475	2,427,376,671	3,307,607	(1,909,442,641)	521,241,637
JACKSON COUNTY	453,342,800	0	0	0	453,342,800	22,911,562	476,254,362	648,957	0	476,903,319
TOTAL WHOLESALE	2,774,627,050	3,448,456,518	(236,729,664)	0	5,986,353,904	243,642,482	6,229,996,386	8,489,156	(3,448,456,518)	2,790,029,024
TOTAL BILLED SALES	29,166,661,862	3,448,456,518	(236,729,664)	149,303	32,378,538,019	2,361,136,972	34,739,674,991	47,337,172	(3,448,456,518)	31,338,555,645
COMPANY USE	42,922,443	0	0	0	42,922,443	4,414,729	47,337,172	(47,337,172)	0	0
ENERGY LOSSES										
TRANSMISSION	1,129,033,665	0	183,954,052	(74,131)	1,312,913,586	(1,312,913,586)	0	0	0	0
DISTRIBUTION	999,937,675	0	52,775,612	(75,172)	1,052,638,115	(1,052,638,115)	0	0	0	0
TOTAL ENERGY LOSSES	2,128,971,340	0	236,729,664	(149,303)	2,365,551,701	(2,365,551,701)	0	0	0	0
TOTAL SYSTEM INPUT	31,338,555,645	3,448,456,518	0	0	34,787,012,163	0	34,787,012,163	0	(3,448,456,518)	31,338,555,645

ALLOCATION
FACTOR
0.001362626

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.4

Request:

Are the avoided generating capacity costs in DR1.1 above market-based costs of capacity?

a. If not, what is the basis for the avoided capacity costs listed in response to DR 1.1?
b. What is the basis for avoided T&D capacity estimates?

Objection:

Duke Energy Indiana objects to this request on the basis that it is vague, ambiguous, and overly broad as the term "above market-based costs" has not been defined; therefore, it is not possible to determine if the Company's Avoided Generation Capacity Costs previously provided in response to OUCC 1.1 are above market-based costs.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. The Avoided Capacity costs listed in Duke Energy Indiana's response to OUCC 1.1 are derived in the same manner that the Company has always used in Cause No. 43955. The cost of building a peaker plant, including both the levelized capital cost and the fixed O&M costs, is provided by the Company's IRP group and that cost is escalated using an annual escalator also provided by the Company's IRP group. For this DSM-8 filing, the starting point value was $67.24/KW-year in 2018 dollars and the escalator was 2.5% per year.

b. The Avoided T&D costs were provided by the Company's rates group and were based on calculations performed in 2016 using information from various sources including the Company's Asset Accounting and Load Forecasting group, along with information provided by the Company in FERC Form 1. These values were used to compare the amount of money invested in T&D infrastructure for projects specifically performed to account for growth in customer load. The total amount of these investments was divided by the overall system load growth to determine a system average costs per KW-year of T&D investments. This initial starting point was escalated to future dollars using a third-party index provided by Handy Whitman that estimates the escalation of investments in Distribution and Transmission plant equipment. This index varies slightly from year to year but averaged approximately 2.2% per year during the period included in this proceeding.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.5

Request:

Please designate the date at which DEI will first have insufficient resource capacity.

Objection:

Duke Energy Indiana objects to this data request on the basis that it is vague, ambiguous, and not reasonably calculated to lead to the discovery of admissible evidence. The term "insufficient resource capacity" is not defined or reasonably limited in scope.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

See Duke Energy Indiana's most recent IRP.

Witness: Scott Park

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.6

Request:

Who was responsible for running the DSMore model?

Response:

The DSMore model runs for this proceeding were prepared by various individuals in the DSM Analytics group, reporting to Tom Wiles.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.7

Request:

Does DEI plan to make any capacity purchases or acquisitions in:

a. 2020?
b. 2021?
c. 2022?
d. 2023?

Response:

The IRP includes 2 MW of solar in 2020, 16 MW of CHP in 2021 and 100 MW of solar in 2023.

Witness: Scott Park

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.8

Request:

What is the discount rate for avoided capacity used in the DSMore model?

Response:

The discount rate for avoided capacity used in the DSMore model in this proceeding was 7.17%.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.9

Request:

Does DEI assume the current cost of capacity is the same as the cost of avoided capacity? If yes, please explain why.

Objection:

Duke Energy Indiana objects to this data request on the basis that it is vague, ambiguous, and overly broad as the term "current cost of capacity" is not defined or reasonably limited in scope.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.10

Request:

Referencing the California Standard Practice Manual[1], page 25 of the manual shows the formula for Bpa which contains the variable UACt. In regards to capacity benefits portion of UACt, , what numbers are used by DEI for UACt for:

a. t=1 (2020)
b. t=2 (2021)
c. t=3 (2022)
d. t=4 (2023)

Response:

Please note that the values provided below are the annual values that would need to be multiplied times the expected KW savings for each measure in each vintage year of the portfolio presented in DSM-8 in order to calculated the UACt variable for each measure.

a. t=1, Year = 2020 – Avoided Generation Capacity = $70.65/KW-year, Avoided T&D = $71.90/KW-year.
b. t=2, Year = 2021 – Avoided Generation Capacity = $72.41/KW-year, Avoided T&D = $73.49/KW-year.
c. t=3, Year = 2022 – Avoided Generation Capacity = $74.22/KW-year, Avoided T&D = $75.14/KW-year.
d. t=4, Year = 2023 – Avoided Generation Capacity = $76.08/KW-year, Avoided T&D = $76.85/KW-year.

1 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.11

Request:

If DEI assumes UACt is the same as the cost of capacity contained in the response to DR (1), please explain why.

Response:

As explained in Duke Energy Indiana's response to OUCC 1.10, the values Duke Energy Indiana provided in its response to OUCC 1.10 are the annual values that would need to be multiplied times the expected KW savings for each measure in the portfolio. These are the same annual values provided in Duke Energy Indiana's response to OUCC 1.1.

Duke Energy Indiana has explained (see response to OUCC 1.04) that the values used for calculating Avoided Capacity and Avoided T&D are based on the same methodology as approved in Cause No. 43955 DSM-4 and those costs have been updated using the most current information.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.12

Request:

Do any EM&V reports performed for DEI completed since January 1, 2018 concerning general service A-line LED bulbs make recommendations for a lighting baseline post January 1, 2020? If yes, please provide the report and the location of the recommendation.

Response:

Two EM&V reports completed since January 1, 2018 concern A-line LEDs, namely the "Duke Energy Indiana Energy Efficient Appliances and Devices Program Evaluation Report" dated October 31, 2018, attached as OUCC Attachment 1.12-B and the "Duke Energy Indiana Agency LED Program 2016-2017" evaluation report, dated August 10, 2018, attached as OUCC Attachment 1.12-A.

The evaluation report dated October 31, 2018, did not make an explicit recommendation for baseline wattages past January 2020, but the evaluators accounted for baseline adjustment through 2021 by truncating the in-service rate ("ISR") trajectory to account for the impact of the second phase of EISA implementation, per UMP recommendations. The evaluation report dated August 10, 2018, did not make recommendations for a lighting baseline post January 1, 2020.

Note that these evaluations were completed prior to the September 4, 2019 "Notice of Proposed Determination" which created additional uncertainty regarding appropriate baseline wattages post-2020.

Witness: Jean P. Williams

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.13

Request:

What is the assumption of the baseline for general service A-line LED bulbs after January 1, 2020?

Response:

At the present time, the backstop requirement will not go in place January 1, 2020. Therefore, the independent, third-party evaluator for Duke Energy recommends the continued use of a 43 watt halogen as the baseline for A-Line LEDs.

Witness: Jean P. Williams

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.14

Request:

What is the basis for the assumption(s) listed in (13)?

Response:

The baseline for the assumption for general service A-line LED bulbs after January 1, 2020, are based on the two (2) evaluation reports indicated in Duke Energy Indiana's response to OUCC 1.12, attached to such response as Attachments OUCC 1.12-A and 1.12-B.

Witness: Jean P. Williams

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.15

Request:

Please provide the Net Present Value of Benefits associated with a single 9W standard A-Line light bulb measure as used in the following programs in 2020:

a. Energy Education Program for Schools
b. Multifamily EE Products and Services
c. Residential Energy Assessments
d. Residential Energy Assessments – Extra Bulbs
e. Smart saver residential (Lighting)
    i. Online Saving Store
    ii. Free lighting
    iii. Retail lighting
f. Small Business Energy Saver
g. Smart Saver Non-Residential (Prescriptive)

Response:

a. Savings are based on total Energy Efficiency Kit and not broken out separately by measure in annual filings.

b. $19.16

c. Savings are based on total Energy Efficiency Kit and not broken out separately by measure in annual filings.

d. $16.61

e. i. $7.76
   ii. $8.46
   iii. $8.13

f. Lighting is not broken out separately by lighting type. Total KWh provided by the implementation contractor in the tracking database for Daytime, Nighttime and 8760 measures are adjusted based on on-site metering and verification conducted by the evaluation contractor.

g. Interior - $68.87

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.16

Request:

Please provide the number of 9W standard A-Line light bulb measure planned to be distributed in the following programs in 2020:

a. Energy Education Program for Schools
b. Multifamily EE Products and Services
c. Residential Energy Assessments
d. Residential Energy Assessments – Extra Bulbs
e. Smart saver residential (Lighting)
    i. Online Saving Store
    ii. Free lighting
    iii. Retail lighting
f. Small Business Energy Saver
g. Smart Saver Non-Residential (Prescriptive)

Response:

See Duke Energy Indiana's response to OUCC 1.19.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.17

Request:

What is the average cost DEI expects to pay for a single 9W standard A-Line light bulb given away or sold as part of the Smart saver Residential program in:

a. 2020?
b. 2021?
c. 2022?
d. 2022?

Response:

See Duke Energy Indiana's response to OUCC 1.20.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.18

Request:

Please provide the Net Present Value of Benefits associated with a single 9W standard A-Line light bulb measure as used in the following programs in 2020:

a. Energy Education Program for Schools
b. Multifamily EE Products and Services
c. Residential Energy Assessments
d. Residential Energy Assessments – Extra Bulbs
e. Smart saver residential (Lighting)
    i. Online Saving Store
    ii. Free lighting
    iii. Retail lighting
f. Small Business Energy Saver
g. Smart Saver Non-Residential (Prescriptive)

Response:

See Duke Energy Indiana's Response to OUCC 1.15.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.19

Request:

Please provide the number of 9W standard A-Line light bulb measure planned for distribution in the following programs in 2020 through 2023:

a. Energy Education Program for Schools
b. Multifamily EE Products and Services
c. Residential Energy Assessments
d. Residential Energy Assessments – Extra Bulbs
e. Smart saver residential (Lighting)
    i. Online Saving Store
    ii. Free lighting
    iii. Retail lighting
f. Small Business Energy Saver
g. Smart Saver Non-Residential (Prescriptive)

Response:

		2020	2021	2022	2023	
a.	Energy Education Program for Schools	-	-	-	-	includes only specialty bulbs
b.	Multifamily EE Products and Services	206,244	195,924	117,564	58,788	
c.	Residential Energy Assessments	1,478	-	-	-	specialty bulbs starting 7/1
d.	Residential Energy Assessments - Extra Bulbs	7,939	3,953	4,293	4,379	
e. i.	Smart $aver® Residential (Lighting) Online Saving Store	10,068	-	-	-	
e. ii.	Smart $aver® Residential (Lighting) Free Lighting	28,927	-	-	-	
e. iii.	Smart $aver® Residential (Lighting) Retail Lighting	75,623	30,251	24,200	19,360	
f.	Small Business Energy Saver	Not broken out by technology type; provided from vendor at total kwh only				
g.	Smart $aver® Non-Residential Prescriptive	10,131	10,333	10,333	10,333	

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

SUPPLEMENTAL RESPONSE 1/23/2020
SUPPLEMENTAL INFORMATION IS IN BOLD
OUCC 1.19

Request:

Please provide the number of 9W standard A-Line light bulb measure planned for distribution in the following programs in 2020 through 2023:

a. Energy Education Program for Schools
b. Multifamily EE Products and Services
c. Residential Energy Assessments
d. Residential Energy Assessments – Extra Bulbs
e. Smart saver residential (Lighting)
    i. Online Saving Store
    ii. Free lighting
    iii. Retail lighting
f. Small Business Energy Saver
g. Smart Saver Non-Residential (Prescriptive)

Response:

		2020	2021	2022	2023	
a.	Energy Education Program for Schools	-	-	-	-	includes only specialty bulbs
b.	Multifamily EE Products and Services	206,244	195,924	117,564	58,788	
c.	Residential Energy Assessments	1,478	-	-	-	specialty bulbs starting 7/1
d.	Residential Energy Assessments - Extra Bulbs	7,939	3,953	4,293	4,379	
e. i.	Smart $aver® Residential (Lighting) Online Saving Store	10,068	-	-	-	
e. ii.	Smart $aver® Residential (Lighting) Free Lighting	28,927	-	-	-	
e. iii.	Smart $aver® Residential (Lighting) Retail Lighting	75,623	30,251	24,200	19,360	
f.	Small Business Energy Saver	Not broken out by technology type; provided from vendor at total kwh only				
g.	Smart $aver® Non-Residential Prescriptive	10,131	10,333	10,333	10,333	

Supplemental Response:

		2020	2021	2022	2023	
a.	Energy Education Program for Schools	-	-	-	-	includes only specialty bulbs
b.	Multifamily EE Products and Services	206,244	195,924	117,564	58,788	
c.	Residential Energy Assessments	2,509	8,335	8,585	8,411	
d.	Residential Energy Assessments - Extra Bulbs	7,939	3,953	4,293	4,379	
e. i.	Smart $aver® Residential (Lighting) Online Saving Store	10,068	-	-	-	
e. ii.	Smart $aver® Residential (Lighting) Free Lighting	28,927	-	-	-	
e. iii.	Smart $aver® Residential (Lighting) Retail Lighting	75,623	30,251	24,200	19,360	
f.	Small Business Energy Saver	Not broken out by technology type; provided from vendor at total kwh only				
g.	Smart $aver® Non-Residential Prescriptive	10,131	10,333	10,333	10,333	

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.22

Request:

Please provide the number of standard A-Line light bulb measures included in each energy efficiency kit to be used in the following programs in 2020 through 2023:

a. Energy Education Program for Schools kits
b. Residential Energy Assessments

Response:

a. Energy Education Program for Schools kits – Zero, the kit will transition to two (2) specialty bulbs beginning in January 2020.
b. Residential Energy Assessments – Two, from January 1st – June 30th. Zero, beginning on July 1st with specialty bulbs replacing A-Line.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.23

Request:

The following questions refer to the new Outdoor Lighting Modernization Program proposed by DEI:

a. Please provide the kW and annual kWh savings per fixture for each type of conversion proposed
b. Please provide the incentive amount per fixture for each type of conversion proposed.
c. Please provide the direct cost for installing each type of conversion proposed.
d. Is the incentive paid to participants a direct payment or bill credit?

Response:

a. See table below.

LED fixture	Coincident kW	Annual kWh savings
Exterior LED Fixture Replacing up to 175 Watt Fixture	0	257
Exterior LED Fixture Replacing up to 176-250 Watt Fixture	0	746
Exterior LED Fixture Replacing up to 251-400 Watt Fixture	0	2982
Exterior LED Fixture Replacing greater than 400 Watt Fixture	0	2481

b. As indicated in the testimony of Amy B. Dean on Page 5, incentives are as follows:
   a. $30 per fixture up to 175 watts
   b. $50 per fixture between 176-250 watts
   c. $75 per fixture between 251-400 watts
   d. $200 per fixture replaced greater than 400 watts

c. Direct costs for installation are as follows:

Description	Equip Type	Color	Technology	Fixture Cost
50W Standard LED-BLACK	Fixture	Black	LED	$312.15
70W Standard LED-BLACK	Fixture	Black	LED	$370.80
110W Standard LED-BLACK	Fixture	Black	LED	$376.69
150W Standard LED-BLACK	Fixture	Black	LED	$440.34
220W Standard LED-BLACK	Fixture	Black	LED	$520.14
280W Standard LED-BLACK	Fixture	Black	LED	$726.43

d. Incentives will be paid directly to participants.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 1
Received: December 13, 2019

OUCC 1.20

Request:

What is the average cost DEI pays for a single 9W standard A-Line light bulb planned to be given away or sold as part of the Smart Saver Residential program in:

a. 2020?
b. 2021?
c. 2022?
d. 2023?

Response:

SmartSaver Program	**2020**	**2021**	**2022**	**2023**
Online Store	$2.00	N/A	N/A	N/A
Free LED	$2.22	N/A	N/A	N/A
Retail Program	$2.27	N/A	N/A	N/A

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 2
Received: December 19, 2019

OUCC 2.1

Request:

Please provide the Net Present Value of Benefits associated with a single 9W standard A-Line light bulb measure as used in the following programs in 2021:

a. Energy Education Program for Schools
b. Multifamily EE Products and Services
c. Residential Energy Assessments
d. Residential Energy Assessments Smart saver residential (Lighting)
    i. Online Saving Store
    ii. Free lighting
    iii. Retail lighting
e. Small Business Energy Saver
f. Smart Saver Non-Residential (Prescriptive)

Objection:

Duke Energy Indiana objects to the Requests to the extent the Requests are vague and ambiguous and provide no basis from which Duke Energy Indiana can determine what information is sought.

Response:

Notwithstanding the foregoing objection and in the spirit of cooperation, Duke Energy Indiana answers as follows:

a. See objection above. Answering further, in 2021, this program does not include any 9W standard A-Line light bulbs.

b. $20.11

c. See objection above. Answering further, in 2021, this program does not include any 9W standard A-Line light bulbs.

d. See objection above. Subject to and without waiving or limiting its objection, Duke Energy Indiana states as follows: To the extent the OUCC intended to indicate "Smart Saver Residential (Lighting)" only without "Residential Energy Assessments" at the beginning of the request, Duke Energy Indiana responds as follows:

i. N/A – measure is not offered in 2021
ii. N/A – measure is not offered in 2021
iii. $8.54

e. In the Small Business Energy Saver program, lighting is not broken out separately by lighting type; rather, total KWh provided by the implementation contractor in the tracking database for Daytime, Nighttime and 8760 measures are adjusted based on on-site metering and verification conducted by the evaluation contractor.

f. The value of single 9W standard A-Line light bulb in this program is $71.95 (Interior).

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 2
Received: December 19, 2019

SUPPLEMENTAL RESPONSE 1/23/2020
SUPPLEMENTAL INFORMATION IS IN BOLD
OUCC 2.1

Request:

Please provide the Net Present Value of Benefits associated with a single 9W standard A-Line light bulb measure as used in the following programs in 2021:

a. Energy Education Program for Schools
b. Multifamily EE Products and Services
c. Residential Energy Assessments
d. Residential Energy Assessments Smart saver residential (Lighting)
    i. Online Saving Store
    ii. Free lighting
    iii. Retail lighting
e. Small Business Energy Saver
f. Smart Saver Non-Residential (Prescriptive)

Objection:

Duke Energy Indiana objects to the Requests to the extent the Requests are vague and ambiguous and provide no basis from which Duke Energy Indiana can determine what information is sought.

Response:

Notwithstanding the foregoing objection and in the spirit of cooperation, Duke Energy Indiana answers as follows:

a. See objection above. Answering further, in 2021, this program does not include any 9W standard A-Line light bulbs.

b. $20.11

c. See objection above. Answering further, in 2021, this program does not include any 9W standard A-Line light bulbs.

d. See objection above. Subject to and without waiving or limiting its objection, Duke Energy Indiana states as follows: To the extent the OUCC intended to indicate "Smart Saver Residential (Lighting)" only without "Residential Energy Assessments" at the beginning of the request, Duke Energy Indiana responds as follows:

i. N/A – measure is not offered in 2021
ii. N/A – measure is not offered in 2021
iii. $8.54

e. In the Small Business Energy Saver program, lighting is not broken out separately by lighting type; rather, total KWh provided by the implementation contractor in the tracking database for Daytime, Nighttime and 8760 measures are adjusted based on on-site metering and verification conducted by the evaluation contractor.

f. The value of single 9W standard A-Line light bulb in this program is $71.95 (Interior).

Supplemental Response:

Notwithstanding the foregoing objection and in the spirit of cooperation, Duke Energy Indiana answers as follows:

a. See objection above. Answering further, in 2021, this program does not include any 9W standard A-Line light bulbs.

b. $20.11

c. **See objection above. Answering further, in 2021, net present value of benefits are based on total Energy Efficiency kit and not broken out separately by measure in annual filings. To the extent the OUCC also intended to indicate "Residential Energy Assessments – Extra Bulbs", the value of a single 9W standard A-Line light bulb for the extra bulb portion is $17.49.**

d. See objection above. Subject to and without waiving or limiting its objection, Duke Energy Indiana states as follows: To the extent the OUCC intended to indicate "Smart Saver Residential (Lighting)" only without "Residential Energy Assessments" at the beginning of the request, Duke Energy Indiana responds as follows:

i. N/A – measure is not offered in 2021
ii. N/A – measure is not offered in 2021
iii. $8.54

e. In the Small Business Energy Saver program, lighting is not broken out separately by lighting type; rather, total KWh provided by the implementation contractor in the tracking database for Daytime, Nighttime and 8760 measures are adjusted based on on-site metering and verification conducted by the evaluation contractor.

f. The value of single 9W standard A-Line light bulb in this program is $71.95 (Interior).

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 2
Received: December 19, 2019

OUCC 2.2

Request:

What is the average cost DEI expects to pay for a single 9W standard A-Line light bulb given away or sold as part of the Smart saver Residential program in:

a. 2020?
b. 2021?
c. 2022?
d. 2022?

Objection:

Duke Energy Indiana objects to this data requests on the grounds that it has already been asked and answered.

Response:

Subject to and without waiving or limiting its response, Duke Energy Indiana responds as follows: See Duke Energy Indiana's response to OUCC 1.17 and 1.20.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 2
Received: December 19, 2019

OUCC 2.5

Request:

Please explain the reasons for the budget changes in the 2020-2023 Plan from the 2019 Plan for:

a. Residential Lighting
b. Residential EE Assessments
c. Residential Multi-Family EE
d. Smart Saver Non-Residential Prescriptive

Objection:

Duke Energy Indiana objects to this request as vague and ambiguous and provides no basis from which Duke Energy Indiana can determine what information is sought.

Response:

Notwithstanding the foregoing objection and in the spirit of cooperation, Duke Energy Indiana responds as follows:

a. See objection stated above. Subject to and without waiving or limiting its response, Duke Energy Indiana states as follows: There is not a line in the Duke Energy Indiana portfolio budget entitled "Residential Lighting."

b. The residential energy assessment program changes beginning in 2020 include additional measures added in 2019 (bathroom aerators and pipewrap), an increase in participation for approximately 1,000 assessments based on actual assessments performed in previous years and factored in an increased cost per audit in the amount of $27.00.

c. For Residential Multi-family EE, the 2019 budget was based on launch assumptions of the program which proved to be lower than the actual opportunity. The program vendor and Program staff have identified greater opportunities than previously estimated. The 2020-2023 budgets represent the actual opportunities that have been identified in Duke Energy Indiana.

d. See objection stated above. There is not a line in the Duke Energy Indiana portfolio budget entitled "Smart Saver Non-Residential Prescriptive." Subject to and without waiving or limiting its response, Duke Energy Indiana states as follows: Budget changes for Smart Saver Non-Residential are a response to increased participation and anticipated demand in the market.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 2
Received: December 19, 2019

OUCC 2.6

Request:

Please provide by year and month, if applicable, the following for each program:

a. Measures included
   i. Quantity of each measure
   ii. Cost of each measure
   iii. Expected gross kW of each measure
   iv. Expected gross annual kWh of each measure
   v. Expected effective life of each measure

Objection:

Duke Energy Indiana objects to this request as unduly burdensome because it is not limited in scope to any relevant time period. Duke Energy Indiana also objects to this request as it is not relevant to this proceeding to the extent it requests information outside of the Plan period at issue in this proceeding.

Response:

Subject to and without waiving or limiting its objections and in the spirit of cooperation, Duke Energy Indiana responds as follows: Assuming this request is asking about the measures included in Duke Energy Indiana's proposed Plan from 2020 through 2023, see Attachment OUCC 2.6-A.

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.1

Request:

How many of what measures will be contained in the Energy Efficiency Starter Kits provided through the Energy Education Program for Schools for:

a. 2020
b. 2021
c. 2022
d. 2023
e. What will be the specific types and quantities of specialty LED light bulbs contained in the kits in the above years?

Response:

a-d. See table below for Energy Efficiency Starter Kit measures for the 2020-2023 period.

e. The kit includes two 5-watt candelabras.

2020 - 2023 K12 Kit Contents	**Qty**
1.5 GPM low flow shower head	**1**
1.5 GPM kitchen faucet aerator with swivel and flip valve	**1**
Water temperature gauge card (Hot Water Temp Card)	**1**
5 Watt Candelabra	**2**
1.0 GPM needle spray bathroom faucet aerator	**1**
Combination Pack of switch and outlet gasket insulators (12/pk) - 8 outlets and 4 socket gaskets	**12**
Energy Efficient Limelight style night light	**1**
Water flow meter bag	**1**
Duke Energy labeled DOE “Energy Savers” booklet	**1**
Roll of Teflon tape for showerhead	**1**

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.2

Request:

What will be the specific types and quantities of specialty LED light bulbs contained in the kits provided through the Residential Energy assessments program after June 30, 2020?

Response:

As you will see in Supplemental OUCC 1.19, the portfolio filing includes A-line bulbs for Residential Energy Assessments after June 30, 2020.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.3

Request:

The response to OUCC DR 1.19 c shows quantities of 9 Watt LED standard A-Line light bulbs (extra bulbs) being distributed as part of the Residential Energy Assessments Program in 2020 through 2023. The response to OUCC DR 2.1 c states the program does not contain any 9 Watt LED standard A-Line light bulbs in 2021. Please explain this apparent discrepancy.

Response:

As indicated in Duke Energy Indiana's Supplemental Response to OUCC 1.19 c and Supplemental OUCC 2.1 c, the Residential Energy Assessments Program does include standard A-Line light bulbs being distributed. At the time of the portfolio filing, specialty bulb pricings had not been fully vetted and were not included in the portfolio program design. We are investigating these potential changes.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.4

Request:

In reference to the response to OUCC DR 2.1 f, please provide the calculations explaining the NPV of $71.95 for a single 9W standard A-Line light bulb in the Smart Saver Non-Residential program.

Response:

The NPV of $71.95 for a single 9W standard A-Line light bulb is calculated by summing the NPV of Avoided Capacity, Energy and T&D, which equals $743,499 and then dividing by 10,333 participants, resulting in a per participant Net Benefit of $71.95.

Measure Description	Total NPV Avoided Cost of Capacity / Total Sum of 2021	Total NPV Avoided Cost of Energy / Total Sum of 2021	Total NPV Avoided Cost of T&D / Total Sum of 2021	Total NPV AC Sum of 2021	Participation Sum of 2021	Per Participant Net Benefit Sum of 2021
LED A Lamps	157,315	428,762	157,422	743,499	10,333	$71.95

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.5

Request:

Please explain the budget and measure changes in the 2020-2023 Plan compared to the 2019 Plan for the Smart Saver Residential (Lighting) program in regards to:

a. Online Savings Store
b. Free Lighting
c. Retail Lighting.

Response:

a. Online Savings Store – Decrease in overall LED bulb participation, with an increase of participation for smart thermostats. For example, 2019 included a budget of 1,164 smart thermostats while 2020 shows 9,497 smart thermostats. Also, other new measures such as LED fixtures, dehumidifiers, and air purifiers have participation increases in 2020-2023 as compared to the 2019 Plan.
b. Free Lighting- In 2020, 95% drop in participation levels as a result of the program sunsetting in Quarter 2 of 2020. Beyond 2020, there is no Free LED participation budgeted.
c. Retail Lighting – Year over year decreases to account for shifting program strategy to target "hard to reach" underserved markets. Doing so will limit participation opportunities for the program but will result in better opportunity for net impacts as compared to big box retailers. Also, reduction of A line bulbs in out years.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.7

Request:

In reference to the Public Efficiency Streetlighting program:

a. Please confirm the direct cost of the installed measures will not be charged to the DSM program nor recovered through the DSM tracker.
b. Please confirm whether the direct cost of the measures are included in the benefit/cost tests. If not, please explain why not.
c. Please confirm whether lost revenues will be claimed for this program. If yes, please provide the calculations supporting the estimated amounts of lost revenues for which DEI will seek recovery.
d. Is it DEI's intent to earn a return on and of the direct costs of installing the program measures and claim a shareholder incentive through the DSM tracker.

Response:

a. The direct cost of installed measures will not be charged to the DSM program or recovered through the DSM tracker.

b. The incremental cost of direct costs is included in benefit/cost tests.

c. Yes, lost revenues will be claimed for this program. This will be the incremental kwh sales loss multiplied by the fixed energy component.

	Monthly Lost Revenue KWH	Lost Revenue Rate	Lost Revenue $
2020	-		
2021	3,142,982	0.02460533	$ 77,334
2022	10,103,822	0.02460533	$ 248,608
2023	18,188,140	0.02460533	$ 447,525

d. Through the DSM tracker, the public efficiency streetlighting program will only earn a shareholder incentive, not a return on or of direct costs of installation.

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.8

Request:

It appears from the response to OUCC DR 2.6 (Attachment 2.6-A) the Agency Portal Assistance program will cease to be offered after 2020. Please confirm and explain the decision to cease offering the program.

Response:

There are currently no budgeted impacts for the Agency Assistance Portal program after 2020. Duke Energy Indiana is evaluating potential program modifications due to changing market conditions to see if there are alternatives to make the program effective in the long term.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

OUCC 3.10

Request:

For witness Mr. Scott Park: Page 6 of direct testimony.

a. Please explain why the "Filing Program Costs ($MM)" for each year 2020 - 2023 is less than the sum of annual "Program Costs and Administrative Overhead" and "M&V Costs" from Ms. Holbrook's CONFIDENTIAL Workpaper 1 (KKH) page 1 and "Shared Savings Incentive" from CONFIDENTIAL Workpaper 1 (KKH) page 2. These annual sums shown on OUCC CONFIDENTIAL Attachment DR 3, "Total" row.
b. If the full costs of the DSM programs were modeled, would all of the same programs been selected in the IRP process?

Objection:

Duke Energy Indiana objects to this request as vague, ambiguous, overly broad and unduly burdensome as the OUCC has not specified what "same programs" it is referring to in subpart b above.

Response:

a. The referenced table in Mr. Park's Direct Testimony shows a comparison between only the EE portion of the IRP process and the EE portion of this DSM-8 Proposed Portfolio. The information from Ms. Holbrook's Direct Testimony also includes information related to the Demand Response programs in the Proposed Portfolio.

While preparing the response to this data request the Company discovered formula errors in the spreadsheet used to summarize the IRP Program Costs portion included in Mr. Park's Direct Testimony; however, these errors only impact the presentation of the data in certain tables in Mr. Park's Direct Testimony and did not impact the IRP analysis, nor did it change the conclusion presented in his Direct Testimony that the DSM-8 Proposed Portfolio is consistent with the 2018 IRP.

In addition, Mr. Park's original data in his Direct Testimony labeled as "Filing Program Costs ($MM)" included only the Direct Program Costs associated with the DSM-8 Proposed Portfolio; however, the estimated Shared Savings Incentive associated with the EE portion of the Proposed Portfolio should also be included to provide a comparison that is more consistent with the EE Portfolio revenue requirement assumptions in the IRP.

As a result of these adjustments, the following table shows the relationship between the Revenue Requirements included in the 2018 IRP and the equivalent information from the DSM-8 Proposed Portfolio.

Incremental 2020-23	**2020**	**2021**	**2022**	**2023**
IRP MWh	156,757	157,314	160,220	164,447
Filing MWh	182,706	186,417	193,011	191,415
IRP MW	27	30	31	32
Filing MW	25	24	24	25
IRP Program Costs ($MM)	$36.69	$37.11	$38.68	$40.86
Filing Program Costs ($MM)	$36.27	$36.25	$36.93	$37.09

Percentage of System Data* 2020-23	**2020**	**2021**	**2022**	**2023**
IRP MWh	0.5%	0.5%	0.5%	0.5%
Filing MWh	0.5%	0.5%	0.6%	0.6%
IRP MW	0.4%	0.5%	0.5%	0.5%
Filing MW	0.4%	0.4%	0.4%	0.4%
IRP Program Costs	4.1%	4.3%	4.2%	4.3%
Filing Program Costs	4.1%	4.2%	4.0%	3.9%

*System Data used for this comparison is from the 2018 Preferred Portfolio in the Reference Case Scenario and the System Cost information used for this comparison does not reflect sunk costs.

b. See Duke Energy Indiana's objection above. Subject to and without waiving or limiting its objections, Duke Energy Indiana states as follows: All of the costs components discussed in part 3.10 a above were included in the modeling performed in the IRP process; therefore, the results of the IRP process would not change.

Witness: Scott Park

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 3
Received: January 8, 2020

SUPPLEMENTAL RESPONSE 2/27/2020
SUPPLEMENTAL INFORMATION IS IN BOLD
OUCC 3.11

Request:

In response to OUCC DR 1.3, DEI provided "OUCC Attachment 1.3-B". This data is from the 12 months ended September 30, 2002. Please provide the most up-to-date data for DEI's Retail Sales Allocated Losses (Cell G21) and Retail Sales Sub-Total (Cell H21). In the alternative, if DEI has already provided this data to the OUCC as part of its filing in Cause No. 45253, please identify where this data is included.

Objection:

Duke Energy Indiana objects to this request to the extent it seeks a calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing.

Supplemental Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana states as follows:

In Cause No. 45253, the line losses proposed are included in MSFR WP COSS 43-MTD, the applicable figures are:

29,915,025,595 kwh (cell I208) – 27,921,491,980 kwh (cell E208) divided by 29,915,025,595 kwh equals 6.6%.

As the above amounts are proposed amounts in Duke Energy Indiana's current base rate case pending before the Commission in Cause No. 45253, the DSM proceeding continues to utilize the previously approved 7.43%.

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.1

Request:

Following up on DEI response to OUCC DR-3.1:

a. What is the assumed installation rate for the 5 Watt candelabra LED lights included in the kit?
b. What is the installation rate for the 9 Watt GSL LED lights previously included in the kits?
c. What is the estimated kWh savings of the new kit and the coincident kW of the new kit?
d. What is DEI's estimate of the Net Present Value of savings under the UCT for the new kit?

Response:

a. ISR (in service rate) is assumed to be comparable to the current ISR levels from previous K12 evaluations. The ISR from the kit evaluation including CFL's was 73% (13 watt) and 70% (18 watt).

   ISR will be verified and updated in the program EM&V for the kit that contains the 5 watt candelabras which was incorporated in January 2020. Timing of evaluation is unknown at this time; however, upon sufficient participation the evaluation will be scheduled.

b. The program is currently under evaluation with final report scheduled for June 2020, which will provide ISR for the 9 Watt LED.

c. No changes to estimated kWh or coincident kW were made with the new kit. EM&V will update the kWh savings and coincident kW upon completion of the evaluation.

d. No cost or impact changes have been made to the kit at this time. The Net Present Value of benefits for this program in 2020 is $236.30.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.2

Request:

Following up on DEI response to OUCC DR-3.1:

a. What is the amount of the incentive paid for the single 9 Watt A-line bulb in this program (Energy Efficiency Education Program for Schools)?
b. What is the measure life used in the calculation of the NPV of benefits for the single 9 Watt A-line bulb in this program?
c. What is the assumed gross annual kWh hours of savings used in the calculation of the NPV of benefits for the single 9 Watt A-line bulb in this program?
d. What is the assumed gross kW of savings used in the calculation of the NPV of benefits for the single 9 Watt A-line bulb in this program?
e. If the answers to b. through d. above are different than the values listed in the March 6, 2019 Duke Energy Indiana Non-Residential Smart Saver Prescriptive Program Evaluation Report, please explain the differences?

Objection:

Duke Energy Indiana objects to the request on the grounds and to the extent it is vague and ambiguous in that the term "incentive paid" is not defined and provides no basis from which Duke Energy Indiana can determine what information is sought.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Duke Energy Indiana assumes for purposes of this response that the request is seeking the cost for each 9 Watt A-line bulb in the program, which was $2.22 each, excluding packaging and shipping, but was purchased at the overall kit level.
b. Measure life is at the kit level and is not calculated at the individual measure component. The kit measure life is 8 years.
c. The kWh is at the kit level and is not calculated at the individual measure component.
d. The kWh is at the kit level and is not calculated at the individual measure component.

e. The values are different because the Non-Residential Smart $aver Prescriptive program impacts are calculated at selected measure level and the K12 Program impacts are evaluated at the kit level.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.3

Request:

Following up on DEI response to OUCC DR-3.4:

a. Please provide the details of the NPV calculation for the Total NPV Avoided Cost of Capacity/Total Sum of 2021($157,315) including the estimated kW savings by year, NTG factors, coincident peak factors, discount rate, gross-up factors to the generator and any other assumptions used in the calculation of this number.

b. Please provide the details of the NPV calculation for the Total NPV Avoided Cost of Energy/Total Sum of 2021($428,762) including the estimated annual kWh savings by year, NTG factors, discount rate, gross-up or line loss and any other assumptions used in the calculation of this number.

Response:

a. LED A Lamps have an estimated total annual kW savings for 2021 of 265 kW (Gross at the Plant) or .0256592 coincident kW per participant. The NTG factor is 73.25%, discount rate is 7.17%, and gross up factor to the generator is 8.0264%.

b. LED A Lamps have an estimated total annual kWh savings for 2021 of 1,264,286 kWh (Gross at the Plant) or 122.34 kWh per participant. The NTG factor is 73.25%, discount rate is 7.17%, and gross up factor to the generator is 8.0264%.

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.4

Request:

Following up on DEI response to OUCC DR-3.5a:

a. What LED fixtures will be offered through the Online Savings Store?
b. What are DEI's planned incentives for each LED fixture listed in response to a. above?
c. What is the expected measure life for the LED fixtures and what is the basis for the estimate?
d. What is the expected kW and annual kWh savings for each LED fixture listed in a., above and what is the baseline to which each is compared?

Response:

a. As approved in April 2019 by the Oversight Board ("OSB"), the Company is offering direct wire fixtures, portable fixtures, and outdoor photocell fixtures in the Online Savings Store.
b. Direct wire: incentive = $12
   Portable fixture: incentive = $5
   Outdoor photocell fixtures: incentive = $10
c. Direct wire: 18 years; source 2016 MidAtlantic TRM
   Portable fixture: 20 years; source 2016 MidAtlantic TRM
   Outdoor photocell fixtures: 20 years; source product literature
d. Direct wire: .005 kW, 37.4 kWh, baseline wattage 66
   Portable fixture: .003 kW, 19.9 kWh, baseline wattage 31
   Outdoor photocell fixture: 0 kW, 227.9 kWh, baseline wattage 84

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.5

Request:

Following up on DEI response to OUCC DR-3.5b, what are the reasons for discontinuing the Free LED lighting?

Response:

The Free LED program is scheduled to discontinue in Duke Energy Indiana in the second quarter of 2020 as a result of potential efficiency standards for general service bulbs that may be imposed as a part of the Energy Independence and Security Act ("EISA"). This legislative change in standard will diminish the impact of the program, as well as its cost effectiveness, making it no longer a viable program for the Company to continue to offer. Although, at this time, there is still uncertainty as to how and when this legislation will be imposed, Duke Energy Indiana still plans to move forward with its sunsetting strategy.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.6

Request:

Following up on DEI response to OUCC DR-3.5c:

a. Please define "hard to reach" underserved markets" as used in response to OUCC DR3.5c.
b. Are there specific retail outlets DEI is targeting in in its program strategy?
c. Is it DEI's plan to exclude "big box" retailers as an outlet for LED lighting?
d. What is meant by "...reduction of A line bulbs in out years?"
    i. Does "reduction: mean discontinuing? If so, when?
    ii. The response to OUCC DR 2.1d, states the 9 Watt A line LED bulbs will not be offered in 2021. Is 2021 and thereafter considered "out years?"

Response:

a. Hard to reach/underserved stores are dollar/discount stores (for example, Dollar Tree) that tend to attract lower income shoppers that have a much lower adoption rate of energy efficient lighting. These customers would not have been likely to purchases energy efficient lighting had Duke Energy Indiana's incentives not been there; as advised by EM&V evaluation studies.

b. Here is a current list of participating Duke Energy Indiana retailers, as well as their store classification type:

Store Type	**Retailer Name**
Hardware	Ace Hardware
DIY	Lowes, Menards, The Home Depot
Dollar/Discount	Dollar Tree, Goodwill, Habitat ReStore
Big Box	Meijer, Walmart

c. At this time, Duke Energy Indiana continues to partner with Meijer and Walmart who are classified as "big box" retailers for its Retail Lighting program.

d.

i. At the time of preparing the filing, unlike other lighting measures offered through the Retail Lighting program, (GSL) A-Line bulbs were not considered exempt from EISA. While the DOE has issued final rules regarding the EISA implementation, there is still uncertainty as to what the result of potential legal challenges will be. Given this, to mitigate any potential negative impact, Duke Energy Indiana has strategically elected to remove A-line incentives beginning in the third quarter of 2020, understanding that shutting down a retail program could take several months inclusive of reporting of point of sale ("POS").

ii. The Free LED program and A line incentives that are a part of the Retail Lighting program are planned to be phased out starting in the third quarter of 2020. The Company plans to still offer incentives on other lighting measures, as a part of the Retail Lighting program, beyond the third quarter of 2020. As it relates to Residential Smart $aver lighting, 2021 and thereafter were considered "out years".

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.7

Request:

Following up on DEI response to OUCC DR-3.7b:

a. Please explain what is meant by "incremental" cost of direct costs.
b. Are the "incremental" costs used in the calculation of the benefit/cost tests the same as those listed in response to OUCC DR1.23c? If not, please explain

Response:

a. The incremental cost was calculated as the LED cost minus baseline HID cost.

b. No. Duke Energy Indiana's response to OUCC 1.23 c shows the full fixture cost.

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.9

Request:

Referencing the testimony of Timothy J. Duff at page 19, lines 6-10:

a. Please provide all assumptions and calculations supporting the estimated financial incentive of $119,000.
b. Please explain why DEI should not be awarded a shareholder incentive for the Low Income Weatherization program similar to that proposed for the Low Income Neighborhood program.

Response:

a.

Low Income Neighborhood Program					
	2020	2021	2022	2023	Total
Projected Avoided Costs	$ 347,215	$ 361,331	$ 378,612	$ 399,840	$ 1,486,998
Shared Savings Percentage	8.0%	8.0%	8.0%	8.0%	8.0%
Projected Incentive	$ 27,777.19	$ 28,906.50	$ 30,288.96	$ 31,987.18	$ 118,959.84

The projected avoided costs associated with the calculations above are found in the Confidential Workpaper of Petitioner's Witness, Karen K. Holbrook.

b. The Company did not include the Low Income Weatherization program in the calculation of the performance incentive, because it felt that it would be categorized as a Home Energy Assistance Program and hence not eligible for the Commission to approve a financial incentive associated with it.

Witness: Timothy J. Duff

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 4
Received: January 24, 2020

OUCC 4.10

Request:

Referencing Confidential Attachment OUCC 1.3-A:

a. There is a significant increase (20%) in the avoided energy cost between 2024 and 2025 and other significant increases thereafter until 2030. Please explain the reason(s) for these increases.
b. Do the avoided energy prices shown on Confidential Attachment OUCC 1.3-A include a carbon tax or adder? If yes, what is the adder in each year.

Response:

a. This increase is the result of a carbon tax being included in the Avoided energy costs.

b. Yes, these prices include a carbon tax. The following table shows the amount added in each year.

Reference Case Avoided Energy	
Year	**CO2 Tax Adder**
2020	$ -
2021	$ -
2022	$ -
2023	$ -
2024	$ -
2025	$ 5.25
2026	$ 7.66
2027	$ 9.86
2028	$ 11.97
2029	$ 14.23
2030	$ 15.08
2031	$ 17.22
2032	$ 18.06
2033	$ 19.31
2034	$ 21.79
2035	$ 23.56
2036	$ 26.56
2037	$ 28.46

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 5
Received: February 7, 2020

OUCC 5.4

Request:

Following up on DEI response to OUCC DR-4.4b:

a. Regarding the measure called "portable fixture." Please confirm this term refers to the LED desk lamp shown on the Duke Energy online store and attached as OUCC DR 5 Attachment 1.

b. Please confirm the price to customers for the desk lamp referenced above is $16.98 each plus $5.00 shipping plus Indiana sales tax. If this is incorrect, please provide the correct pricing, shipping and sales tax numbers.

c. Regarding the $5.00 incentive referenced in response to OUCC DR 4.4.b for the portable fixture, please explain how the incentive is paid and to whom.

Response:

a. Yes, portable fixture is a LED desk lamp as shown in OUCC DR 5 Attachment 1.

b. The picture included in OUCC DR 5 Attachment 1 is from the Duke Energy Indiana online store; however, it is from the additional product section. This section has non-incented products for sale. This section allows customers to purchase additional products without an incentive. The pricing, plus shipping, plus Indiana sales tax is correct for non-incented product as referenced in OUCC DR 5 Attachment 1.

c. The incentive is reduced from the retail price at check out. The customer pays the reduced price (after the incentive is applied). The incentive amount is paid to the program's vendor by Duke Energy.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 5
Received: February 7, 2020

OUCC 5.5

Request:

Following up on DEI response to OUCC DR-4.4c:

a. The response states the measure life is 20 years and the source of this information is the 2016 MidAtlantic TRM. Please provide a copy of that document and the page number for the referenced information.

Response:

a. Duke Energy New Product Development engaged Navigant to assist with the development of the portable fixture measure. Navigant recommended Duke Energy use the May 2016 Mid-Atlantic Technical Resource Manual for the source of measure life. See Attachment OUCC 5.5-A from the 2016 MidAtlantic TRM that reflects a measure life of 20 years. Specific measure life information is indicated on page 67 of the full TRM.

Witness: Jean P. Williams

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 5
Received: February 7, 2020

OUCC 5.6

Request:

Following up on DEI response to OUCC DR 4.4d:

a. What is the baseline for kW and kWh savings attributable to the portable fixture measure and the source documentation of the estimated savings? Please provide a copy of the document and a page number of the referenced document where this information appears.

Response:

As indicated in Duke Energy Indiana's response to OUCC 4.4, the baseline for kW and kWh is 31 watts. The baseline wattage is calculated using inputs provided to Duke Energy by Navigant and weighted by participation.

Witness: Jean P. Williams

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 5
Received: February 7, 2020

OUCC 5.7

Request:

Following up on DEI response to OUCC DR-4.4:

a. Please provide the same information requested in 5.1 through 5.3 applicable to the "Direct wire" and "Outdoor photocell fixture" offered through the Online Savings Store.
b. Please explain what a "Direct Wire" LED Fixture is and designate which product this is in the DEI On-line Store.
c. Please provide the Net Present Value of Benefits for each measure:
    i. Portable LED fixture
    ii. Direct wire LED Fixture
    iii. Outdoor photocell fixture.

Objection:

Duke Energy Indiana objects to the Request to the extent the Request is vague and ambiguous and provides no basis from which Duke Energy Indiana can determine what information is sought in regard to subpart a. above, as it is unclear as to what the OUCC means by "same information requested in 5.1 through 5.3".

Response:

a. Subject to and without waiting or limiting its objection, Duke Energy Indiana states as follows: To the extent the OUCC is requesting NPV information similar to what was provided before Mr. Haselden completed his analysis, Duke Energy Indiana responds as follows:

Row Labels	Participants 2020	Total NPV Avoided Cost of Capacity / Total 2020	Total NPV Avoided Cost of Energy / Total 2020	Total NPV Avoided Cost of T&D / Total 2020	Total NPV Avoided Cost 2020	Net Benefit Per Participant 2020
11786: Marketplace LED Fixtures Direct Wire	136	576	2,254	576	3,406	25.04
11788: Marketplace Photocell Outdoor Lights Fixtures	35		3,227	151	3,379	96.53

Row Labels	Annual kWh Gross at Plant Total 2020	kWh per Participant Gross at Plant 2020	Annual kW Gross at Plant Total 2020	Coincident kW Gross at Plant 2020	Freeridership %
11786: Marketplace LED Fixtures Direct Wire	5,498.87	40.43	0.76	0.00558	0.152
11788: Marketplace Photocell Outdoor Lights Fixtures	8,616.95	246.20	-	-	0.152

Discount rate is 7.17%, and gross up factor to the generator is 8.0264% for all measures.

b. A LED fixture that is wired directly into a home. It is not easily unplugged or moved.

Currently the following products are on the online store.

i. ETi 11.5w 4000K 7" White Pull-Chain Ceiling Fixture
ii. RAB 10w 3000K 4" White Ceiling Fixture
iii. RAB 10w 3500K 8" White Ceiling Fixture
iv. RAB 12w 3500K 12" White Ceiling Fixture
v. RAB 20w 3500K 16" White Ceiling Fixture
vi. Royal Pacific 23w 3000K 16" Brushed Nickel Semi-Flush Ceiling Fixture
vii. Royal Pacific 7w 3000K 18" White Undercabinet Fixture

c.

Row Labels	Participants 2020	Total NPV Avoided Cost of Capacity / Total 2020	Total NPV Avoided Cost of Energy / Total 2020	Total NPV Avoided Cost of T&D / Total 2020	Total NPV Avoided Cost 2020	Net Benefit Per Participant 2020
11786: Marketplace LED Fixtures Direct Wire	136	576	2,254	576	3,406	25.04
11788: Marketplace Photocell Outdoor Lights Fixtures	35		3,227	151	3,379	96.53
11787: Marketplace LED Fixtures Portable	110	264	1,065	264	1,594	14.49

Row Labels	Annual kWh Gross at Plant Total 2020	kWh per Participant Gross at Plant 2020	Annual kW Gross at Plant Total 2020	Coincident kW Gross at Plant 2020	Freeridership %
11786: Marketplace LED Fixtures Direct Wire	5,498.87	40.43	0.76	0.00558	0.152
11788: Marketplace Photocell Outdoor Lights Fixtures	8,616.95	246.20	-	-	0.152
11787: Marketplace LED Fixtures Portable	2,361.61	21.47	0.33	0.00296	0.152

Discount rate is 7.17% and gross up factor to the generator is 8.0264% for all measures.

Witness: Amy B. Dean and Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 5
Received: February 7, 2020

OUCC 5.8

Request:

Following up on DEI response to OUCC DR-4.7,

a. Please provide the baseline HID costs for each fixture listed in response to OUCC DR 3.7.
b. Please explain why the full cost of replacing the HID fixture with an LED fixture is not appropriate when calculating the benefit/cost tests.

Response:

a. The average baseline HID cost, based on weighted average participation, is $225.11.

Description	Technology	Fixture Cost
100W Gray (RAL7038) Type II 120V	HID	$212.92
200W Gray (RAL7038) Type III 120V	HID	$218.84
250W Gray (RAL7038) Type III 120V	HID	$252.04
400W Gray (RAL7038) Type III 120V	HID	$251.18

b. Energy and demand savings are evaluated for cost effectiveness on an incremental basis. A baseline of expected energy usage is established, then energy usage is evaluated in the high efficiency case; it is the difference of these two values that is used to evaluate avoided cost benefits. Savings and costs must be synchronized for a valid comparison between the baseline state and the high efficiency (LED) state. Appropriately, the cost of the baseline state option must be subtracted from the cost of the high efficiency option to establish incremental costs relative to the incremental savings.

Witness: Amy B. Dean

OUCC
IURC Cause No. 43955 DSM-8
Data Request Set No. 5
Received: February 7, 2020

OUCC 5.9

Request:

Referencing Workpaper 1 (JPW), Please explain why the Shareholder Incentive costs (found on Confidential Workpaper 1 (KKH)) are NOT included in the calculation of the TRC or RIM test calculations.

Response:

The Company uses the Cost Effectiveness score methodology contained in the California Standard Practice Manual. Shareholder Incentive costs are not defined as part of the calculation of the TRC or RIM test calculations.

Witness: Jean P. Williams

CALIFORNIA STANDARD PRACTICE MANUAL

ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

OCTOBER 2001

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Chapter 1

Basic Methodology

Background

Since the 1970s, conservation and load management programs have been promoted by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) as alternatives to power plant construction and gas supply options. Conservation and load management (C&LM) programs have been implemented in California by the major utilities through the use of ratepayer money and by the CEC pursuant to the CEC legislative mandate to establish energy efficiency standards for new buildings and appliances.

While cost-effectiveness procedures for the CEC standards are outlined in the Public Resources Code, no such official guidelines existed for utility-sponsored programs. With the publication of the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* in February 1983, this void was substantially filled. With the informal "adoption" one year later of an appendix that identified cost-effectiveness procedures for an "All Ratepayers" test, C&LM program cost effectiveness consisted of the application of a series of tests representing a variety of perspectives-participants, non-participants, all ratepayers, society, and the utility.

The Standard Practice Manual was revised again in 1987-88. The primary changes (relative to the 1983 version), were: (1) the renaming of the "Non-Participant Test" to the "Ratepayer Impact Test"; (2) renaming the All-Ratepayer Test" to the "Total Resource Cost Test."; (3) treating the "Societal Test" as a variant of the "Total Resource Cost Test;" and, (4) an expanded explanation of "demand-side" activities that should be subjected to standard procedures of benefit-cost analysis.

Further changes to the manual captured in this (2001) version were prompted by the cumulative effects of changes in the electric and natural gas industries and a variety of changes in California statute related to these changes. As part of the major electric industry restructuring legislation of 1996 (AB1890), for example, a public goods charge was established that ensured minimum funding levels for "cost effective conservation and energy efficiency" for the 1998-2002 period, and then (in 2000) extended through the year 2011. Additional legislation in 2000 (AB1002) established a natural gas surcharge for similar purposes. Later in that year, the Energy Security and Reliability Act of 2000 (AB970) directed the California Public Utilities Commission to establish, by the Spring of 2001, a distribution charge to provide revenues for a self generation program and a directive to consider changes to cost-effectiveness methods to better account for reliability concerns.

In the Spring of 2001, a new state agency — the Consumer Power and Conservation Financing Authority — was created. This agency is expected to provide additional revenues in the form of state revenue bonds that could supplement the amount and type of public financial resources to finance energy efficiency and self generation activities.

The modifications to the Standard Practice Manual reflect these more recent developments in several ways. First, the "Utility Cost Test" is renamed the "Program Administrator Test" to include the assessment of programs managed by other agencies. Second, a definition of self generation as a type of "demand-side" activity is included. Third, the description of the various potential elements of "externalities" in the Societal version of the TRC test is expanded. Finally the limitations section outlines the scope of this manual and elaborates upon the processes traditionally instituted by implementing agencies to adopt values for these externalities and to adopt the the policy rules that accompany this manual.

Demand-Side Management Categories and Program Definitions

One important aspect of establishing standardized procedures for cost-effectiveness evaluations is the development and use of consistent definitions of categories, programs, and program elements.

This manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. 'Conservation' in this context includes all 'energy efficiency improvements'. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.

Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer's side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.

In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer's thermal needs. Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

Fuel substitution and load building programs were relatively new to demand-side management in California in the late 1980s, born out of the convergence of several factors that translated into average rates that substantially exceeded marginal costs. Proposals by utilities to implement programs that increase sales had prompted the need for additional procedures for estimating program cost effectiveness. These procedures maybe applicable in a new context. AB 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation. Hence, self-generation was also added to the list of demand side management programs for cost-effectiveness evaluation. In some cases, self-generation programs installed with incremental load are also included since the definition of self-generation is not necessarily confined to projects that reduce electric load on the grid. For example, suppose an industrial customer installs a new facility with a peak consumption of 1.5 MW, with an integrated on-site 1.0 MW gas fired DG unit. The combined impact of the new facility is *load building* since the new facility can draw up to 0.5 MW from the grid, even when the DG unit is running. The proper characterization of each type of demand-side management program is essential to ensure the proper treatment of inputs and the appropriate interpretation of cost-effectiveness results.

Categorizing programs is important because in many cases the same specific device can be and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program. Similarly, natural gas-fired self-generation, as well as self-generation units using other non-renewable fossil fuels, must be treated as fuel-substitution. In common with other types of fuel-substitution, any costs of gas transmission and distribution, and environmental externalities, must be accounted for. In addition, cost-effectiveness analyses of self-generation should account for utility interconnection costs. Similarly, a thermal energy storage device should be treated as a load management program when the predominant effect is to shift load. If the acceptance of a utility incentive by the customer to, install the energy storage device is a decisive aspect of the customer's decision to remain an electric utility customer (i.e., to reject or defer the option of installing a gas-fired cogeneration system), then the predominant effect of the thermal energy storage device has been to substitute electricity service for the natural gas service that would have occurred in the absence of the program.

In addition to Fuel Substitution and Load Building Programs, recent utility program proposals have included reference to "load retention," "sales retention," "market retention," or "customer retention" programs. In most cases, the effect of such programs is identical to either a Fuel Substitution or a Load Building program — sales of one fuel are increased relative to sales without the program. A case may be made, however, for defining a separate category of program called "load retention." One unambiguous example of a load retention program is the situation where a program keeps a customer from relocating to another utility service area. However, computationally the equations and guidelines included in this manual to accommodate Fuel Substitution and Load Building programs can also handle this special situation as well.

Basic Methods

This manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC), and Total Resource Cost (TRC). A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. The results of each perspective can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

Table I summarizes the cost-effectiveness tests addressed in this manual. For each of the perspectives, the table shows the appropriate means of expressing test results. The primary unit of measurement refers to the way of expressing test results that are considered by the staffs of the two Commissions as the most useful for summarizing and comparing demand-side management (DSM) program cost-effectiveness. Secondary indicators of cost-effectiveness represent supplemental means of expressing test results that are likely to be of particular value for certain types of proceedings, reports, or programs.

This manual does not specify how the cost-effectiveness test results are to be displayed or the level at which cost-effectiveness is to be calculated (e.g., groups of programs, individual programs, and program elements for all or some programs). It is reasonable to expect different levels and types of results for different regulatory proceedings or for different phases of the process used to establish proposed program-funding levels. For example, for summary tables in general rate case proceedings at the CPUC, the most appropriate tests may be the RIM lifecycle revenue impact, Total Resource Cost, and Program Administrator Cost test results for programs or groups of programs. The analysis and review of program proposals for the same proceeding may include Participant test results and various additional indicators of cost-effectiveness from all tests for each individual program element. In the case of cost-effectiveness evaluations conducted in the context of integrated long-term resource planning activities, such detailed examination of multiple indications of costs and benefits may be impractical.

Table I
Cost-Effectiveness Tests

Participant	
Primary	Secondary
Net present value (all participants)	Discounted payback (years) Benefit-cost ratio Net present value (average participant)
Ratepayer Impact Measure	
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW) Net present value	Lifecycle revenue impact per unit Annual revenue impact (by year, per kWh, kW, therm, or customer) First-year revenue impact (per kWh, kW, therm, or customer) Benefit-cost ratio
Total Resource Cost	
Net present value (NPV)	Benefit-cost ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)
Program Administrator Cost	
Net present value	Benefit-cost ratio Levelized cost (cents or dollars per unit of energy or demand)

Rather than identify the precise requirements for reporting cost-effectiveness results for all types of proceedings or reports, the approach taken in this manual is to (a) specify the components of benefits and costs for each of the major tests, (b) identify the equations to be used to express the results in acceptable ways; and (c) indicate the relative value of the different units of measurement by designating primary and secondary test results for each test.

It should be noted that for some types of demand-side management programs, meaningful cost-effectiveness analyses cannot be performed using the tests in this manual. The following guidelines are offered to clarify the appropriated "match" of different types of programs and tests:

1. For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts.

2. For any program where more than one fuel is affected, the preferred unit of measurement for the RIM test is the lifecycle revenue impacts per customer, with gas and electric components reported separately for each fuel type and for combined fuels.

3. For load building programs, only the RIM tests are expected to be applied. The Total Resource Cost and Program Administrator Cost tests are intended to identify cost-effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options.

4. Levelized costs may be appropriate as a supplementary indicator of cost per unit for electric conservation and load management programs relative to generation options and gas conservation programs relative to gas supply options, but the levelized cost test is not applicable to fuel substitution programs (since they combine gas and electric effects) or load building programs (which increase sales).

The delineation of the various means of expressing test results in **Table 1** is not meant to discourage the continued development of additional variations for expressing cost-effectiveness. Of particular interest is the development of indicators of program cost effectiveness that can be used to assess the appropriateness of program scope (i.e. level of funding) for General Rate Case proceedings. Additional tests, if constructed from the net present worth in conformance with the equations designated in this manual, could prove useful as a means of developing methodologies that will address issues such as the optimal timing and scope of demand-side management programs in the context of overall resource planning.

Balancing the Tests

The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests. Issues related to the precise weighting of each test relative to other tests and to developing formulas for the definitive balancing of perspectives are outside the scope of this manual. The manual, however, does provide a brief description of the strengths and weaknesses of each test (Chapters 2, 3, 4, and 5) to assist users in qualitatively weighing test results.

Limitations: Externality Values and Policy Rules

The list of externalities identified in Chapter 4, page 27, in the discussion on the Societal version of the Total Resource Cost test is broad, illustrative and by no means exhaustive. Traditionally, implementing agencies have independently determined the details such as the components of the externalities, the externality values and the policy rules which specify the contexts in which the externalities and the tests are used.

Externality Values

The values for the externalities have not been provided in the manual. There are separate studies and methodologies to arrive at these values. There are also separate processes instituted by implementing agencies before such values can be adopted formally.

Policy Rules

The appropriate choice of inputs and input components vary by program area and project. For instance, low income programs are evaluated using a broader set of non-energy benefits that have not been provided in detail in this manual. Implementing agencies traditionally have had the discretion to use or to not use these inputs and/or benefits on a project- or program-specific basis. The policy rules that specify the contexts in which it is appropriate to use the externalities, their components, and tests mentioned in this manual are an integral part of any cost-effectiveness evaluation. These policy rules are not a part of this manual.

To summarize, the manual provides the methodology and the cost-benefit calculations only. The implementing agencies (such as the California Public Utilities Commission and the California Energy Commission) have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation.

Chapter 2

Participant Test

Definition

The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

Benefits and Costs

The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross savings, as opposed to net energy savings[1].

In the case of fuel substitution programs, benefits to the participant also include the avoided capital and operating costs of the equipment/appliance not chosen. For load building programs, participant benefits include an increase in productivity and/or service, which is presumably equal to or greater than the productivity/ service without participating. The inclusion of these benefits is not required for this test, but if they are included then the societal test should also be performed.

The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.

[1] Gross energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program. For fuel substitution and load building programs, gross-to-net considerations account for the impacts that would have occurred in the absence of the program.

How the Results can be Expressed

The results of this test can be expressed in four ways: through a net present value per average participant, a net present value for the total program, a benefit-cost ratio or discounted payback. The primary means of expressing test results is net present value for the total program; discounted payback, benefit-cost ratio, and per participant net present value are secondary tests.

The discounted payback is the number of years it takes until the cumulative discounted benefits equal or exceed the cumulative discounted costs. The shorter the discounted payback, the more attractive or beneficial the program is to the participants. Although "payback period" is often defined as undiscounted in the textbooks, a discounted payback period is used here to approximate more closely the consumer's perception of future benefits and costs.[2]

Net present value (NPVp) gives the net dollar benefit of the program to an average participant or to all participants discounted over some specified time period. A net present value above zero indicates that the program is beneficial to the participants under this test.

The benefit-cost ratio (BCRp) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. The benefit-cost ratio gives a measure of a rough rate of return for the program to the participants and is also an indication of risk. A benefit-cost ratio above one indicates a beneficial program.

Strengths of the Participant Test

The Participants Test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates.

For programs that involve a utility incentive, the Participant Test can be used for program design considerations such as the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation.

These test results can be useful for program penetration analyses and developing program participation goals, which will minimize adverse ratepayer impacts and maximize benefits.

For fuel substitution programs, the Participant Test can be used to determine whether program participation (i.e. choosing one fuel over another) will be in the long-run best interest of the customer. The primary means of establishing such assurances is the net present value, which looks at the costs and benefits of the fuel choice over the life of the equipment.

[2] It should be noted that if a demand-side program is beneficial to its participants (NPVp ≥ 0 and BCRp ≥ 1.0) using a particular discount rate, the program has an internal rate of return (IRR) of at least the value of the discount rate.

Weaknesses of the Participant Test

None of the Participant Test results (discounted payback, net present value, or benefit-cost ratio) accurately capture the complexities and diversity of customer decision-making processes for demand-side management investments. Until or unless more is known about customer attitudes and behavior, interpretations of Participant Test results continue to require considerable judgment. Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects.

Formulae

The following are the formulas for discounted payback, the net present value (NPVp) and the benefit-cost ratio (BCRp) for the Participant Test.

NPV_P	=	Bp - Cp
NPVavp	=	(Bp - Cp) / P
BCRp	=	Bp / Cp
DPp	=	Min j such that Bj > Cj

Where:

NPVp	=	Net present value to all participants
NPVavp	=	Net present value to the average participant
BCRp	=	Benefit-cost ratio to participants
DPp	=	Discounted payback in years
Bp	=	NPV of benefit to participants
Cp	=	NPV of costs to participants
Bj	=	Cumulative benefits to participants in year j
Cj	=	Cumulative costs to participants in year j
P	=	Number of program participants
J	=	First year in which cumulative benefits are cumulative costs.
d	=	Interest rate (discount)

The Benefit (Bp) and Cost (Cp) terms are further defined as follows:

$$BP = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PA_{at}}{(1+d)^{t-1}}$$

$$C = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Where:

BRt	=	Bill reductions in year t
Bit	=	Bill increases in year t

TCt	=	Tax credits in year t
INCt	=	Incentives paid to the participant by the sponsoring utility in year t[3]
PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax[4] • Ongoing operation and maintenance costs include fuel cost • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PACat	=	Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)
Abat	=	Avoided bill from alternate fuel in year t

The first summation in the Bp equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for Bp.

Note that in most cases, the customer bill impact terms (BRt, BIt, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I}(\Delta EG_{it} \times AC:E_{it} \times K_{it}) + \sum_{i=1}^{I}(\Delta DG_{it} \times AC:D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BRt formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I}(\Delta EG_{it} \times AC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I}(\Delta DG_{it} \times AC:D_{it} \times (K_{it} - 1)) + OBI_t$$

Where:

ΔEG_{it}	=	Reduction in gross energy use in costing period i in year t
ΔDG_{it}	=	Reduction in gross billing demand in costing period i in year t
$AC:E_{it}$	=	Rate charged for energy in costing period i in year t

[3] Some difference of opinion exists as to what should be called an incentive. The term can be interpreted broadly to include almost anything. Direct rebates, interest payment subsidies, and even energy audits can be called incentives. Operationally, it is necessary to restrict the term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). Information and services such as audits are not considered incentives for the purposes of these tests. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate must be included in the PC_t term

[4] If money is borrowed by the customer to cover this cost, it may not be necessary to calculate the annual mortgage and discount this amount if the present worth of the mortgage payments equals the initial cost. This occurs when the discount rate used is equal to the interest rate of the mortgage. If the two rates differ (e.g., a loan offered by the utility), then the stream of mortgage payments should be discounted by the discount rate chosen.

$AC:D_{it}$	=	Rate charged for demand in costing period i in year t
K_{it}	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
OBR_t	=	Other bill reductions or avoided bill payments (e.g.,, customer charges, standby rates).
OBI_t	=	Other bill increases (i.e. customer charges, standby rates).
I	=	Number of periods of participant's participation

In load management programs such as TOU rates and air-conditioning cycling, there are often no direct customer hardware costs. However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs.

If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period.

Chapter 3

The Ratepayer Impact Measure Test[5]

Definition

The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

Benefits and Costs

The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased. The avoided supply costs are a reduction in total costs or revenue requirements and are included for both fuels for a fuel substitution program. The increase in revenues are also included for both fuels for fuel substitution programs. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.

The costs for this test are the program costs incurred by the utility, *and/or other entities incurring costs and creating or administering the program,* the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The decreases in revenues and the increases in the supply costs should be calculated for both fuels for fuel substitution programs using net savings.

How the Results can be Expressed

The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW, therm, or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW, therms, or customer); benefit-cost ratio; and net present value. The primary units of measurement are the lifecycle revenue impact, expressed as the change in rates (cents per kWh for electric energy, dollars per kW for electric capacity, cents per therm for natural gas) and the net present value. Secondary test results are the lifecycle revenue

[5] The Ratepayer Impact Measure Test has previously been described under what was called the "Non-Participant Test." The Non-Participant Test has also been called the "Impact on Rate Levels Test."

impact per customer, first-year and annual revenue impacts, and the benefit-cost ratio. LRI_{RIM} values for programs affecting electricity and gas should be calculated for each fuel individually (cents per kWh or dollars per kW and cents per therm) and on a combined gas and electric basis (cents per customer).

The lifecycle revenue impact (LRI) is the one-time change in rates or the bill change over the life of the program needed to bring total revenues in line with revenue requirements over the life of the program. The rate increase or decrease is expected to be put into effect in the first year of the program. Any successive rate changes such as for cost escalation are made from there. The first-year revenue impact (FRI) is the change in rates in the first year of the program or the bill change needed to get total revenues to match revenue requirements only for that year. The annual revenue impact (ARI) is the series of differences between revenues and revenue requirements in each year of the program. This series shows the cumulative rate change or bill change in a year needed to match revenues to revenue requirements. Thus, the ARIRIM for year six per kWh is the estimate of the difference between present rates and the rate that would be in effect in year six due to the program. For results expressed as lifecycle, annual, or first-year revenue impacts, negative results indicate favorable effects on the bills of ratepayers or reductions in rates. Positive test result values indicate adverse bill impacts or rate increases.

Net present value (NPV_{RIM}) gives the discounted dollar net benefit of the program from the perspective of rate levels or bills over some specified time period. A net present value above zero indicates that the program will benefit (lower) rates and bills.

The benefit-cost ratio (BCR RIM) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. A benefit-cost ratio above one indicates that the program will lower rates and bills.

Strengths of the Ratepayer Impact Measure (RIM) Test

In contrast to most supply options, demand-side management programs cause a direct shift in revenues. Under many conditions, revenues lost from DSM programs have to be made up by ratepayers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the program.

An additional strength of the RIM test is that the test can be used for all demand-side management programs (conservation, load management, fuel substitution, and load building). This makes the RIM test particularly useful for comparing impacts among demand-side management options.

Some of the units of measurement for the RIM test are of greater value than others, depending upon the purpose or type of evaluation. The lifecycle revenue impact per customer is the most useful unit of measurement when comparing the merits of programs with highly variable scopes (e.g.,, funding levels) and when analyzing a wide range of programs that include both electric and natural gas impacts. Benefit-cost ratios can also be very useful for program design evaluations to identify the most attractive programs or program elements.

If comparisons are being made between a program or group of conservation/load management programs and a specific resource project, lifecycle cost per unit of energy and annual and first-year net costs per unit of energy are the most useful way to express test results. Of course, this requires developing lifecycle, annual, and first-year revenue impact estimates for the supply-side project.

Weaknesses of the Ratepayer Impact Measure (RIM) Test

Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

RIM test results are also sensitive to assumptions regarding the financing of program costs. Sensitivity analyses and interactive analyses that capture feedback effects between system changes, rate design options, and alternative means of financing generation and non-generation options can help overcome these limitations. However, these types of analyses may be difficult to implement.

An additional caution must be exercised in using the RIM test to evaluate a fuel substitution program with multiple end use efficiency options. For example, under conditions where marginal costs are less than average costs, a program that promotes an inefficient appliance may give a more favorable test result than a program that promotes an efficient appliance. Though the results of the RIM test accurately reflect rate impacts, the implications for long-term conservation efforts need to be considered.

Formulae: The formulae for the lifecycle revenue impact (LRI RIM)' net present value (NPV RIM), benefit-cost ratio (BCR RIM)' the first-year revenue impacts and annual revenue impacts are presented below:

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = I
ARIRIMt	=	FRIRIM	for t = I
	=	(CRIMt - BRIMt)/Et	for t=2, ………….., N
NPVRIM	=	BRIM-CRIM	

BCRRIM` = BRIM/CRIM where:

LRIRIM = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program). (Note: An appropriate choice of kWh, therm, kW, and customer should be made)

FRIRIM = First-year revenue impact of the program per unit of energy, demand, or per customer.

ARIRIM = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRI RIM')

NPVRIM = Net present value levels

BCRRIM = Benefit-cost ratio for rate levels

BRIM = Benefits to rate levels or customer bills
CRIM = Costs to rate levels or customer bills
E = Discounted stream of system energy sales (kWh or therms) or demand sales (kW) or first-year customers. (See Appendix D for a description of the derivation and use of this term in the LRIRIM test.)

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Where:
UACt = Utility avoided supply costs in year t
UICt = Utility increased supply costs in year t
RGt = Revenue gain from increased sales in year t
RLt = Revenue loss from reduced sales in year t
PRCt = Program Administrator program costs in year t
Et = System sales in kWh, kW or therms in year t or first year customers
UACat = Utility avoided supply costs for the alternate fuel in year t
Rlat = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B RIM and C RIM equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

The utility avoided cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UCA_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC:D_{it} \times K_{it})$$

UAC_{at} = (Use UACt formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t \sum_{i=1}^{I} (\Delta EN_{it} \times MC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC:D \times (K_{it} - 1))$$

Where:

[Only terms not previously defined are included here.]

ΔENit	=	Reduction in net energy use in costing period i in year t
ΔDNit	=	Reduction in net demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
MC:Dit	=	Marginal cost of demand in costing period i in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated exactly the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

RGt	=	BIt	* (net-to-gross ratio)
RLt	=	BRt	* (net-to-gross ratio)
Rlat	=	Abat	* (net-to-gross ratio)

Chapter 4

Total Resource Cost Test[6]

Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric).

A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g.,, environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost 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. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant.

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, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program.

[6] This test was previously called the All Ratepayers Test

How the Results Can be Expressed

The results of the Total Resource Cost Test can be expressed in several forms: as a net present value, a benefit-cost ratio, or as a levelized cost. The net present value is the primary unit of measurement for this test. Secondary means of expressing TRC test results are a benefit-cost ratio and levelized costs. The Societal Test expressed in terms of net present value, a benefit-cost ratio, or levelized costs is also considered a secondary means of expressing results. Levelized costs as a unit of measurement are inapplicable for fuel substitution programs, since these programs represent the net change of alternative fuels which are measured in different physical units (e.g.,, kWh or therms). Levelized costs are also not applicable for load building programs.

Net present value (NPVTRC) is the discounted value of the net benefits to this test over a specified period of time. NPVTRC is a measure of the change in the total resource costs due to the program. A net present value above zero indicates that the program is a less expensive resource than the supply option upon which the marginal costs are based.

The benefit-cost ratio (BCRTRC) is the ratio of the discounted total benefits of the program to the discounted total costs over some specified time period. It gives an indication of the rate of return of this program to the utility and its ratepayers. A benefit-cost ratio above one indicates that the program is beneficial to the utility and its ratepayers on a total resource cost basis.

The levelized cost is a measure of the total costs of the program in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the total costs of the program to the utility and its ratepayers on a per kilowatt, per kilowatt hour, or per therm basis levelized over the life of the program.

The Societal Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Test utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view. More specifically, the Societal Test differs from the TRC Test in at least one of five ways. First, the Societal Test may use higher marginal costs than the TRC test if a utility faces marginal costs that are lower than other utilities in the state or than its out-of-state suppliers. Marginal costs used in the Societal Test would reflect the cost to society of the more expensive alternative resources. Second, tax credits are treated as a transfer payment in the Societal Test, and thus are left out. Third, in the case of capital expenditures, interest payments are considered a transfer payment since society actually expends the resources in the first year. Therefore, capital costs enter the calculations in the year in which they occur. Fourth, a societal discount rate should be used[7]. Finally, Marginal costs used in the Societal Test would also contain externality costs of power generation not captured by the market system. An illustrative and

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7 Many economists have pointed out that use of a market discount rate in social cost-benefit analysis undervalues the interests of future generations. Yet if a market discount rate is not used, comparisons with alternative investments are difficult to make.

by no means exhaustive list of 'externalities and their components' is given below (Refer to the Limitations section for elaboration.) These values are also referred to as 'adders' designed to capture or internalize such externalities. The list of potential adders would include for example:

1. The benefit of avoided environmental damage: The CPUC policy specifies two 'adders' to internalize environmental externalities, one for electricity use and one for natural gas use. Both are statewide average values. These adders are intended to help distinguish between cost-effective and non cost-effective energy-efficiency programs. They apply to an average supply mix and would not be useful in distinguishing among competing supply options. The CPUC electricity environmental adder is intended to account for the environmental damage from air pollutant emissions from power plants. The CPUC-adopted adder is intended to cover the human and material damage from sulfur oxides (SOX), nitrogen oxides (NOX), volatile organic compounds (VOC, sometimes called reactive organic gases or ROG), particulate matter at or below 10 micron diameter (PM10), and carbon. The adder for natural gas is intended to account for air pollutant emissions from the direct combustion of the gas. In the CPUC policy guidance, the adders are included in the tabulation of the benefits of energy efficiency programs. They represent reduced environmental damage from displaced electricity generation and avoided gas combustion. The environmental damage is the result of the net change in pollutant emissions in the air basins, or regions, in which there is an impact. This change is the result of direct changes in powerplant or natural gas combustion emission resulting from the efficiency measures, and changes in emissions from other sources, that result from those direct changes in emissions.

2. The benefit of avoided transmission and distribution costs – energy efficiency measures that reduce the growth in peak demand would decrease the required rate of expansion to the transmission and distribution network, eliminating costs of constructing and maintaining new or upgraded lines.

3. The benefit of avoided generation costs – energy efficiency measures reduce consumption and hence avoid the need for generation. This would include avoided energy costs, capacity costs and T&D line

4. The benefit of increased system reliability: The reductions in demand and peak loads from customers opting for self generation, provide reliability benefits to the distribution system in the forms of:
   a. Avoided costs of supply disruptions
   b. Benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid
   c. Marginally decreased System Operator's costs to maintain a percentage reserve of electricity supply above the instantaneous demand
   d. Benefits to customers and the public of avoiding blackouts.

5. Non-energy benefits: Non-energy benefits might include a range of program-specific benefits such as saved water in energy-efficient washing machines or self generation units, reduced waste streams from an energy-efficient industrial process, etc.

6. Non-energy benefits for low income programs: The low income programs are social programs which have a separate list of benefits included in what is known as the 'low income public purpose test'. This test and the sepcific benefits associated with this test are outside the scope of this manual.

7. Benefits of fuel diversity include considerations of the risks of supply disruption, the effects of price volatility, and the avoided costs of risk exposure and risk management.

Strengths of the Total Resource Cost Test

The primary strength of the Total Resource Cost (TRC) test is its scope. The test includes total costs (participant plus program administrator) and also has the potential for capturing total benefits (avoided supply costs plus, in the case of the societal test variation, externalities). To the extent supply-side project evaluations also include total costs of generation and/or transmission, the TRC test provides a useful basis for comparing demand- and supply-side options.

Since this test treats incentives paid to participants and revenue shifts as transfer payments (from all ratepayers to participants through increased revenue requirements), the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results. Average rates and assumptions associated with how other options are financed (analogous to the issue of incentives for DSM programs) are also excluded from most supply-side cost determinations, again making the TRC test useful for comparing demand-side and supply-side options.

Weakness of the Total Resource Cost Test

The treatment of revenue shifts and incentive payments as transfer payments, identified previously as a strength, can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues.

In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers.

Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options.

Formulas

The formulas for the net present value (NPV_{TRC})' the benefit-cost ratio (BCR_{TRC} and levelized costs are presented below:

NPVTRC = BTRC - CTRC
BCRTRC = BTRC /CTRC
LCTRC = LCRC / IMP

Where:

NPVTRC	=	Net present value of total costs of the resource
BCRTRC	=	Benefit-cost ratio of total costs of the resource
LCTRC	=	Levelized cost per unit of the total cost of the resource (cents per kWh for conservation programs; dollars per kW for load management programs)
BTRC	=	Benefits of the program
CTRC	=	Costs of the program
LCRC	=	Total resource costs used for levelizing
IMP	=	Total discounted load impacts of the program
PCN	=	Net Participant Costs

The B_{TRC} C_{TRC} LCRC, and IMP terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$LCRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[(\sum_{i=1}^{n} \Delta EN_{it}) \; or \; (\Delta DN_{it} \;\; where \; I = peak \;\; period) \right]}{(1+d)^{t-1}}$$

[All terms have been defined in previous chapters.]

The first summation in the BTRC equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Chapter 5

Program Administrator Cost Test

Definition

The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

Benefits and Costs

The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided supply costs for the energy-using equipment not chosen by the program participant only in the case of a combination utility where the utility provides both fuels.

The costs for the Program Administrator Cost Test are the program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). For fuel substitution programs, costs include the increased supply costs for the energy-using equipment chosen by the program participant only in the case of a combination utility, as above.

In this test, revenue shifts are viewed as a transfer payment between participants and all ratepayers. Though a shift in revenue affects rates, it does not affect revenue requirements, which are defined as the difference between the net marginal energy and capacity costs avoided and program costs. Thus, if $NPV_{pa} > 0$ and $NPV_{RIM} < 0$, the administrator's overall total costs will decrease, although rates may increase because the sales base over which revenue requirements are spread has decreased.

How the Results Can be Expressed

The results of this test can be expressed either as a net present value, benefit-cost ratio, or levelized costs. The net present value is the primary test, and the benefit-cost ratio and levelized cost are the secondary tests.

Net present value (NPVpa) is the benefit of the program minus the administrator's costs, discounted over some specified period of time. A net present value above zero indicates that this demand-side program would decrease costs to the administrator and the utility.

The benefit-cost ratio (BCRpa) is the ratio of the total discounted benefits of a program to the total discounted costs for a specified time period. A benefit-cost ratio above one indicates that the program would benefit the combined administrator and utility's total cost situation.

The levelized cost is a measure of the costs of the program to the administrator in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the costs of the program to the administrator and the utility on per kilowatt, per kilowatt-hour, or per therm basis levelized over the life of the program.

Strengths of the Program Administrator Cost Test

As with the Total Resource Cost test, the Program Administrator Cost test treats revenue shifts as transfer payments, meaning that test results are not complicated by the uncertainties associated with long-term rate projections and associated rate design assumptions. In contrast to the Total Resource Cost test, the Program Administrator Test includes only the portion of the participant's equipment costs that is paid for by the administrator in the form of an incentive. Therefore, for purposes of comparison, costs in the Program Administrator Cost Test are defined similarly to those supply-side projects which also do not include direct customer costs.

Weaknesses of the Program Administrator Cost Test

By defining device costs exclusively in terms of costs incurred by the administrator, the Program Administrator Cost test results reflect only a portion of the full costs of the resource.

The Program Administrator Cost Test shares two limitations noted previously for the Total Resource Cost test: (1) by treating revenue shifts as transfer payments, the rate impacts are not captured, and (2) the test cannot be used to evaluate load building programs.

Formulas

The formulas for the net present value, the benefit-cost ratio and levelized cost are presented below:

$$NPV_{pa} = B_{pa} - C_{pa}$$
$$BCR_{pa} = B_{pa}/C_{pa}$$
$$LC_{pa} = LC_{pa}/IMP$$

Where:

NPVpa	Net present value of Program Administrator costs
BCRpa	Benefit-cost ratio of Program Administrator costs

LCpa	Levelized cost per unit of Program Administrator cost of the resource
Bpa	Benefits of the program
Cpa	Costs of the program
LCpc	Total Program Administrator costs used for levelizing

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t+1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCpc = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

[All variables are defined in previous chapters.]

The first summation in the Bpa equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Appendix A

Inputs to Equations and Documentation

A comprehensive review of procedures and sources for developing inputs is beyond the scope of this manual. It would also be inappropriate to attempt a complete standardization of techniques and procedures for developing inputs for such parameters as load impacts, marginal costs, or average rates. Nevertheless, a series of guidelines can help to establish acceptable procedures and improve the chances of obtaining reasonable levels of consistent and meaningful cost-effectiveness results. The following "rules" should be viewed as appropriate guidelines for developing the primary inputs for the cost-effectiveness equations contained in this manual:

1. In the past, Marginal costs for electricity were based on production cost model simulations that clearly identify key assumptions and characteristics of the existing generation system as well as the timing and nature of any generation additions and/or power purchase agreements in the future. With a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices, which are derived from recent transactions in California energy markets. Such transactions could include spot market purchases as well as longer term bilateral contracts and the marginal costs should be estimated based on components for energy as well as demand and/or capacity costs as is typical for these contracts.

2. In the case of submittals in conjunction with a utility rate proceeding, average rates used in DSM program cost-effectiveness evaluations should be based on proposed rates. Otherwise, average rates should be based on current rate schedules. Evaluations based on alternative rate designs are encouraged.

3. Time-differentiated inputs for electric marginal energy and capacity costs, average energy rates, and demand charges, and electric load impacts should be used for (a) load management programs, (b) any conservation program that involves a financial incentive to the customer, and (c) any Fuel Substitution or Load Building program. Costing periods used should include, at a minimum, summer and winter, on-, and off-peak; further disaggregation is encouraged.

4. When program participation includes customers with different rate schedules, the average rate inputs should represent an average weighted by the estimated mix of participation or impacts. For General Rate Case proceedings it is likely that each major rate class within each program will be considered as program elements requiring separate cost-effectiveness analyses for each measure and each rate class within each program.

5. Program administration cost estimates used in program cost-effectiveness analyses should exclude costs associated with the measurement and evaluation of program impacts unless the costs are a necessary component to administer the program.

6. For DSM programs or program elements that reduce electricity and natural gas consumption, costs and benefits from both fuels should be included.

7. The development and treatment of load impact estimates should distinguish between gross (i.e., impacts expected from the installation of a particular device, measure, appliance) and net (impacts adjusted to account for what would have happened anyway, and therefore not attributable to the program). Load impacts for the Participants test should be based on gross, whereas for all other tests the use of net is appropriate. Gross and net program impact considerations should be applied to all types of demand-side management programs, although in some instances there may be no difference between gross and net.

8. The use of sensitivity analysis, i.e. the calculation of cost-effectiveness test results using alternative input assumptions, is encouraged, particularly for the following programs: new programs, programs for which authorization to substantially change direction is being sought (e.g.,, termination, significant expansion), major programs which show marginal cost-effectiveness and/or particular sensitivity to highly uncertain input(s).

The use of many of these guidelines is illustrated with examples of program cost effectiveness contained in Appendix B.

Appendix B

Summary of Equations and Glossary of Symbols

Basic Equations

Participant Test

NPVP = BP - CP
NPVavp = (BP - CP) / P
BCRP = BP/CP
DPP = min j such that Bj > Cj

Ratepayer Impact Measure Test

LRIRIM = (CRIM - BRIM) / E
FRIRIM = (CRIM - BRIM) / E for t = 1
ARIRIMt = FRIRIM for t = 1
= (CRIMt- BRIMt)/Et for t=2,... ,N
NPVRIM = BRIM — CRIM
BCRRIM = BRIM /CRIM

Total Resource Cost Test

NPVTRC = BTRC - CTRC
BCRTRC = BTRC / CTRC
LCTRC = LCRC / IMP

Program Administrator Cost Test

NPVpa = Bpa - Cpa
BCRpa = Bpa / Cpa
LCpa = LCpa / IMP

Benefits and Costs

Participant Test

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[(\sum_{i=1}^{n} \Delta EN_{it}) \; or \; (\Delta DN_{it} \; where \; I = peak \; period) \right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

Glossary of Symbols

Abat	=	Avoided bill reductions on bill from alternate fuel in year t
AC:Dit	=	Rate charged for demand in costing period i in year t
AC:Eit	=	Rate charged for energy in costing period i in year t
ARIRIM	=	Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRIRIM*
BCRp	=	Benefit-cost ratio to participants
BCRRIM	=	Benefit-cost ratio for rate levels
BCRTRC	=	Benefit-cost ratio of total costs of the resource
BCRpa	=	Benefit-cost ratio of program administrator and utility costs
BIt	=	Bill increases in year t
Bj	=	Cumulative benefits to participants in year j
Bp	=	Benefit to participants
BRIM	=	Benefits to rate levels or customer bills
BRt	=	Bill reductions in year t
BTRC	=	Benefits of the program
Bpa	=	Benefits of the program
Cj	=	Cumulative costs to participants in year i

Cp	=	Costs to participants
CRIM	=	Costs to rate levels or customer bills
CTRC	=	Costs of the program
Cpa	=	Costs of the program
D	=	discount rate
ΔDgit	=	Reduction in gross billing demand in costing period i in year t
ΔDnit	=	Reduction in net demand in costing period i in year t
DPp	=	Discounted payback in years
E	=	Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers
ΔEgit	=	Reduction in gross energy use in costing period i in year t
ΔEnit	=	Reduction in net energy use in costing period i in year t
Et	=	System sales in kWh, kW or therms in year t or first year customers
FRIRIM	=	First-year revenue impact of the program per unit of energy, demand, or per customer.
IMP	=	Total discounted load impacts of the program
INCt	=	Incentives paid to the participant by the sponsoring utility in year t First year in which cumulative benefits are > cumulative costs.
Kit	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
LCRC	=	Total resource costs used for levelizing
LCTRC	=	Levelized cost per unit of the total cost of the resource
LCPA	=	Total Program Administrator costs used for levelizing
Lcpa	=	Levelized cost per unit of program administrator cost of the resource
LRIRIM	=	Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)-the one-time change in rates-or per customer-the change in customer bills over the life of the program.
MC:Dit	=	Marginal cost of demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
NPVavp	=	Net present value to the average participant
NPVP	=	Net present value to all participants
NPVRIM	=	Net present value levels
NPVTRC	=	Net present value of total costs of the resource
NPVpa	=	Net present value of program administrator costs
OBIt	=	Other bill increases (i.e., customer charges, standby rates)
OBRt	=	Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).
P	=	Number of program participants
PACat	=	Participant avoided costs in year t for alternate fuel devices

PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax • Ongoing operation and maintenance costs • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PRCt	=	Program Administrator program costs in year t
PCN	=	Net Participant Costs
RGt	=	Revenue gain from increased sales in year t
RLat	=	Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)
RLt	=	Revenue loss from reduced sales in year t
TCt	=	Tax credits in year t
UACat	=	Utility avoided supply costs for the alternate fuel in year t
UACt	=	Utility avoided supply costs in year t
PAt	=	Program Administrator costs in year t
UICt	=	Utility increased supply costs in year t

Appendix C.

Derivation of Rim Lifecycle Revenue Impact Formula

Most of the formulas in the manual are either self-explanatory or are explained in the text. This appendix provides additional explanation for a few specific areas where the algebra was considered to be too cumbersome to include in the text.

Rate Impact Measure

The Ratepayer Impact Measure lifecycle revenue impact test (LRIRIM) is assumed to be the one-time increase or decrease in rates that will re-equate the present valued stream of revenues and stream of revenue requirements over the life of the program.

Rates are designed to equate long-term revenues with long-term costs or revenue requirements. The implementation of a demand-side program can disrupt this equality by changing one of the assumptions upon which it is based: the sales forecast. Demand-side programs by definition change sales. This expected difference between the long-term revenues and revenue requirements is calculated in the NPVRIM The amount which present valued revenues are below present valued revenue requirements equals NPVRIM

The LRIRIM is the change in rates that creates a change in the revenue stream that, when present valued, equals the NPVRIM* If the utility raises (or lowers) its rates in the base year by the amount of the LRIRIM' revenues over the term of the program will again equal revenue requirements. (The other assumed changes in rates, implied in the escalation of the rate values, are considered to remain in effect.)

Thus, the formula for the LRIRIM is derived from the following equality where the present value change in revenues due to the rate increase or decrease is set equal to the NPVRIM or the revenue change caused by the program.

$$-NPV_{RIM} = \sum_{t=1}^{N} \frac{LRI_{RIM} \times E_t}{(1+d)^{t-1}}$$

Since the LRI_{RIM} term does not have a time subscript, it can be removed from the summation, and the formula is then:

$$-NPV_{RIM} = LRI_{RIM} \times \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Rearranging terms, we then get:

$$LRI_{RIM} = -NPV_{RIM} \Big/ \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Thus,

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

DSM Shareholder Incentive Based Upon Lost Opportunity to Invest

10 MW Example
EUL = 10 years
30% Initial Award
Normal ROE = 9.5%
Enhanced ROE = 10.0%
WACC Discount Rate = 7%

Year

Line			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	10 MW investment	$1000/kW in year 4 (end)					10,000,000	9,666,667	9,333,333	9,000,000	8,666,667	8,333,333	8,000,000	7,666,667	7,333,333	7,000,000	6,666,667
2	Depreciation (30 years)						-333,333	-333,333	-333,333	-333,333	-333,333	-333,333	-333,333	-333,333	-333,333	-333,333	-333,333
3	Depeciated Balance						9,666,667	9,333,333	9,000,000	8,666,667	8,333,333	8,000,000	7,666,667	7,333,333	7,000,000	6,666,667	6,333,333
4	50% Equity						4,833,333	4,666,667	4,500,000	4,333,333	4,166,667	4,000,000	3,833,333	3,666,667	3,500,000	3,333,333	3,166,667
5	ROE (9.5%)		$0	$0	$0	$0	$459,167	$443,333	$427,500	$411,667	$395,833	$380,000					
6	ROE (10.0%)		$0	$0	$0	$0	$483,333	$466,667	$450,000	$433,333	$416,667	$400,000					
7																	
8	NPV of ROE (9.5%)	$1,537,090.31															
9	NPV of ROE (10.0%)	$1,617,989.80															
10																	
11	Initial Award = 30% of NPV		$485,397	$0	$0	$0	$338,333	$326,667	$315,000	$303,333	$291,667	$280,000					
12	of Enhanced ROE																
13																	
14	NPV	$1,697,271.30															

August 20, 2019

REPORT # E19-389

Results of the 2018 Northwest Residential Lighting Long-Term Monitoring and Tracking Study

Prepared for NEEA:
Jennifer Stout, Market Research and Evaluation, Project Manager

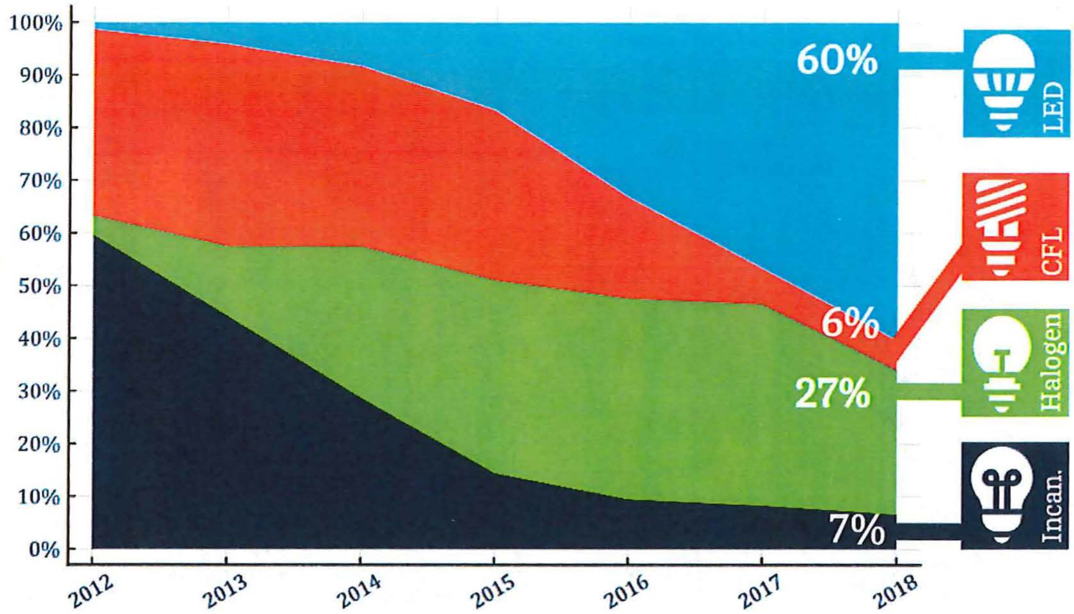
Prepared by:
Katie Parkinson, Senior Associate
Jon Koliner, Associate
Scott Dimetrosky, President

APEX ANALYTICS

Apex Analytics, LLC
2500 30th St., Suite 207
Boulder, CO 80301

Northwest Energy Efficiency Alliance
PHONE
503-688-5400
EMAIL
info@neea.org

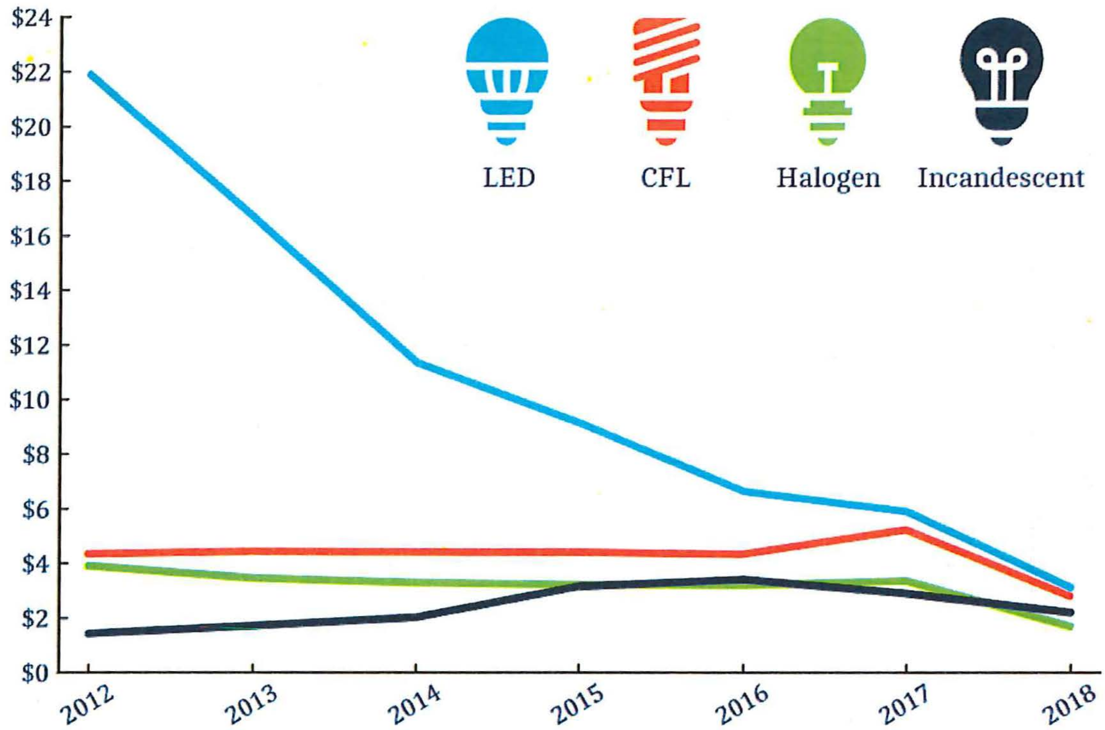
Figure 3. General Purpose Lamps - Technology Shares, 2012-2018



Data source: Weighted combination of sales data and NEEA shelf data

As shown in Figure 4, for specialty lamp categories combined (decorative, globe, reflector, and three-way), incandescents still hold a 43% share. However, LED technology share increased rapidly in 2018 to 50%, at the expense of incandescent lamps..

Figure 10. General Purpose Lamps – Average Price ($/lamp) by Technology, 2012-2018



Data source: Weighted combination of sales data and NEEA shelf data

As shown in Figure 11 below, for each application, falling prices for LEDs have narrowed the price difference between LEDs and other lamp technologies. The price difference has narrowed the most for reflector lamps, with average LED reflector prices in 2018 on par with average prices for halogen reflectors. The largest price difference is in globe lamps, followed by decorative lamps. The low incremental cost of LED reflectors likely contributes to their high and rising technology share. In addition, LED technology is a good fit for reflector lamps which provide directional light.

Percentage Estimates: A-lamps

Field staff asked each store manager whether the percentages of lamps sold in their stores differed by lamp style. Approximately half of DIY store managers (2) and half of small hardware store managers (9) said the percentages of sales did differ by lamp technology. Field staff then asked these store managers approximately what percentages of screw-based A-lamps sold in their store in the last six months were LEDs, CFLs, and incandescents/halogens. Table 12 and Figure 17 show the average of the estimated percentages of A-lamps sold provided by the store managers who were able to give estimates compared to the unweighted percentage of A-lamps that field staff observed in those stores by lamp technology. Similar to estimates provided for all lamps, store managers estimated a slightly higher percentage of LED A-lamps were sold through their stores (76%) than the percentage of LEDs that were stocked (65%).

Table 12: Percentages of Screw-Base A-lamps Sold and Stocked by Lamp Technology in DIY, Small Hardware, Membership Club Stores Combined, 2018-2019

Lamp Technology	% Sold	% Stocked	% Difference of Sales from Stocking
LEDs	76%	65%	-11%
CFLs	2%	6%	4%
Incand./Halogens	22%	29%	7%
Number of Stores	23	23	23
Number of Lamps		49,718	

Figure 17: Percentages of Screw-Base A-Lamps Sold and Stocked by Lamp Technology in DIY, Small Hardware, Membership Club Stores Combined, 2018-2019

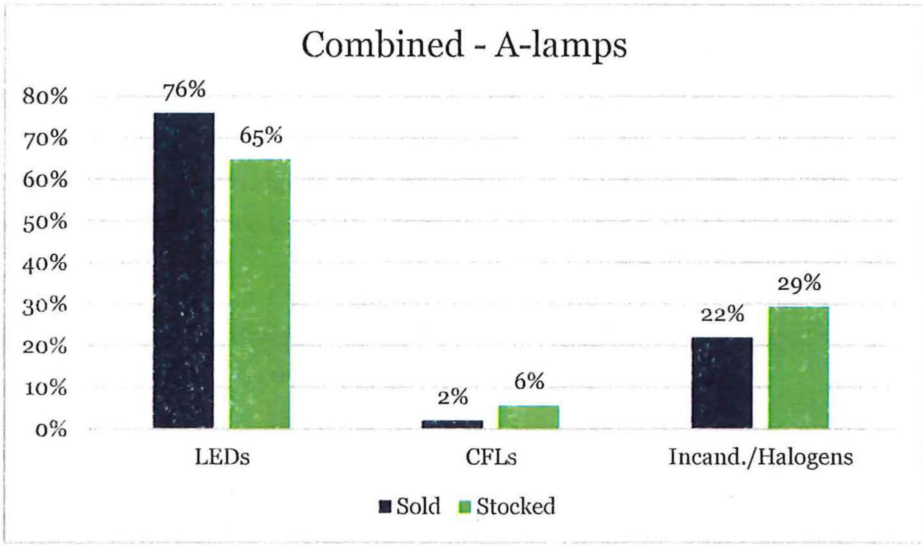


Table 13 and Figure 18 show the average of the estimated percentages of A-lamps sold provided by DIY store managers compared to the unweighted percentage of A-lamps observed in those stores by field staff, by lamp technology.

Desk Lamps - Retail Choices
Date: 2/18/2020, Avon, Indiana

Store: Meijer

Model	Price	Bulb included	Integrated/ Screw-in
Home Alien	$29.99	Yes	Integrated LED
Home LED	$39.99	Yes	Integrated LED
Home Task	$29.99	No	Screw-in Med Base
Home Gooseneck	$29.99	Yes	Integrated LED
Home Architect	$29.99	No	Screw-in Med Base
Home Table	$39.99	Yes	Integrated LED
Home Organizer	$14.99	No	Screw-in Med Base
Home Table	$34.99	No	Screw-in Med Base
Home Copper	$59.99	No	Screw-in Med Base
Home Task	$9.99	No	Screw-in Med Base
Home Vintage Edison	$59.99	Yes*	Screw-in Med Base

* 40 Watt incandesent amber Edison bulb

Store: Target

Model	Price	Bulb included	Integrated/ Screw-in
Desk Lamp	29.99	No	Screw-in Med Base
Lemke	39.99	Yes	Integrated LED
Dean	29.99	Yes	Integrated LED
Threshold Murphy	39.99	Yes	Integrated LED
Threshold cantilever	44.99	Yes	Integrated LED
Threshold Task	39.99	No	Screw-in Med Base
Room Essentials Task	19.99	Yes	Integrated LED
Campanula	19.99	Yes	Integrated LED
Threshold Crosby	47.99	No	Screw-in Med Base
Hudson	49.99	No**	Screw-in Med Base

** Amber Edison LED bulbs offered on shelf

Store: Walmart

Model	Price	Bulb included	Integrated/ Screw-in
Desk	6.88	Yes	Integrated LED
Dimmable desk	19.96	Yes	Integrated LED
Organizer	14.94	No	Screw-in Med Base
Table	34.92	No	Screw-in Med Base
Architect	19.96	Yes	Integrated LED

Count Total	
Lamps	26
Integrated LED	13
Screw-in Med Base, No bulb	12
Screw-in Med Base, bulb included	1

4.4 Value Line LEDs

As LEDs have begun replacing CFLs in energy efficiency programs, the vast majority of program administrators have incented ENERGY STAR LEDs and have chosen not to include non-ENERGY STAR—referred to as "value line"—LEDs in their programs. Value line LEDs are defined as non-ENERGY STAR bulbs that are discounted well below the price of ENERGY STAR LEDs, are often in-house retailer generic-branded bulbs, and have a lower rated lifespan than ENERGY STAR bulbs. This is typically in response to some of the earlier quality challenges with CFLs and concern that if customers have a negative experience (due to poor quality or shorter-than-expected lifetimes) as they first try and then increasingly adopt LEDs, that this could lead to backsliding and negative impressions of the burgeoning technology.

In assessing the delta watts, however, value line LEDs pose a potential challenge because they typically offer a nearly identical wattage as the ENERGY STAR-equivalent lamps. The savings are the same; however, the difference in lifetime can lead to cost savings or other benefits, and dealing with that in detail is complex and common current methods often simply treat them as having the same savings, at both the net and gross level. The question arises: If a program is responsible for shifting customers from a non-ENERGY STAR to an ENERGY STAR LED, should there be any first-year savings?

This protocol recommends evaluators address the shift of sales from non-ENERGY STAR to ENERGY STAR lamps through the estimates of net-to-gross (NTG).[16] At the time of revision to this protocol, most methods of assessing lighting NTG (i.e., intercept surveys, elasticity modeling, sales data modeling, supplier interviews) do not differentiate between value line and ENERGY STAR lamps—that is, the baseline, or counterfactual condition, is assessing the total estimated sales of LEDs in the absence of program intervention. This means that if the baseline/counterfactual condition includes value line LEDs, the estimated "lift" due to program attribution is effectively capturing only the increased sales due to the program above the baseline sales of value line LEDs. In turn, the net savings are already being discounted for the presence and likely sale of value line LEDs.[17]

4.5 Annual Operating Hours

Hours of use (HOU) represents the estimated hours per year that consumers will use the energy-efficient lighting product. Metering studies have shown that the estimated average HOU for efficient lighting ranges from a low of 1.5 hours to a high of 3 hours per day (see Table 5), and have also demonstrated that self-reporting is not accurate. Myriad factors affect the expected number of hours per year that consumers use energy-efficient lighting products, including differences in demographics, housing types and vintages, efficient lighting saturation, room type, electricity pricing, annual days of sunshine, and even an "urban canyon" effect. Thus, data

[16] For jurisdictions that do not adjust savings for NTG, savings cannot be similarly adjusted for the shift from value line to ENERGY STAR LEDs.

[17] This approach may not account for other potential benefits of ENERGY STAR LEDs over value line LEDs, the most significant of which is likely longer lifetimes. When using NTG as an approach to incorporate this sales shift, the lifetime net benefits may be conservative/understated. To account for this, evaluation, measurement, and verification needs to specifically identify the percentage of program participants who shifted from value line to ENERGY STAR LEDs, then make assumptions about their net lifetime benefits.

FILED
July 2, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED DIRECT TESTIMONY
OF
JOHN A. VERDERAME

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

Petitioner's Exhibit 23

July 2, 2019

Q. HAS DUKE ENERGY INDIANA ENTERED INTO ANY SHORT-TERM BUNDLED NON-NATIVE CONTRACTS?

A. Yes. The Company entered into a 5-year 100 MW contract for capacity and energy that expires in 2021.

Q. HOW HAS DUKE ENERGY INDIANA TREATED COSTS AND REVENUES ASSOCIATED WITH THIS AGREEMENT?

A. Duke Energy Indiana Witness Ms. Suzanne Sieferman describes the current treatment in her direct testimony.

Q. GOING FORWARD, HOW DOES DUKE ENERGY INDIANA PROPOSE TO TREAT COSTS AND REVENUES ASSOCIATED WITH THIS AND ANY OTHER POTENTIAL SHORT-TERM BUNDLED NON-NATIVE WHOLESALE SALES CONTRACTS?

A. The Company proposes to share the associated costs and revenues exactly how other non-native margins are shared with customers today through Rider 70, with one adjustment as explained below.

IV. <u>NON-NATIVE SHARING PROPOSAL</u>

Q. DOES DUKE ENERGY INDIANA CURRENTLY HAVE A SHARING MECHANISM FOR THE PROCEEDS FROM NON-NATIVE SALES?

A. Yes. As established in the Company's last base rate proceeding, Cause No. 42359, Duke Energy Indiana has $14.7 million[3] built into base rates. Any amount above or below this amount is split evenly between customers and the Company, and trued up in Cause No.

[3] $18.7 million minus *pro forma* trading expenses of $3,953,000.

Haselden, John

From: Reed, Jeffrey
Sent: Monday, February 24, 2020 1:32 PM
To: Haselden, John
Subject: FW: 43955 DEI DSM 8 - Question RE: DEI response to OUCC DR 2.6

FYI

JR

From: Close, Hillary [mailto:Hillary.Close@BTLaw.com]
Sent: Monday, February 24, 2020 12:39 PM
To: Reed, Jeffrey <jreed@oucc.IN.gov>; Price, Melanie D <Melanie.Price@duke-energy.com>
Subject: RE: 43955 DEI DSM 8 - Question RE: DEI response to OUCC DR 2.6

**** This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. ****

Jeff,

Yes, you are reading the data correctly.

Hillary

Hillary Close | Partner
Barnes & Thornburg LLP
11 South Meridian Street, Indianapolis, IN 46204-3535
Direct: (317) 231-7785 | Fax: (317) 231-7433
BARNES & THORNBURG LLP
Atlanta | California | Chicago | Delaware | Indiana | Michigan | Minneapolis
Ohio | Raleigh | Salt Lake City | Texas | Washington, D.C.

From: Reed, Jeffrey <jreed@oucc.IN.gov>
Sent: Friday, February 21, 2020 1:55 PM
To: Close, Hillary <Hillary.Close@BTLaw.com>; Price, Melanie D <Melanie.Price@duke-energy.com>
Subject: [EXTERNAL]43955 DEI DSM 8 - Question RE: DEI response to OUCC DR 2.6

Hillary, Melanie -

Good Afternoon. Back on February 7, 2020, OUCC, DEI and CAC (outside expert, if I remember correctly) had a call where John Haselden was trying to replicate the net present value of benefits for the non-residential LED A-Line Lamps measure.

OUCC sent DR 2.6 to Duke on this topic. Duke responded, and provided Attachment OUCC 2.6-A. OUCC wants to make certain we understand the data in the Attachment.

For example, we want to confirm:

1) on page 090015419-000143, Smart Saver Non-Residential LED A-Line Lamps, for Jan 2020 – July 2020, the 844 Participants for each month are the estimated number of bulbs to be distributed for that month
2) on the next page, 090015419-000144, Smart Saver Non-Residential LED A-Line Lamps, for Jan 2020 – July 2020, the 15,009 number for each month is the estimated monthly Program Costs.

Are we reading this data correctly? If not, can someone send us a note explaining what this data represents, or can we schedule a call for early next week to discuss?

Thanks,

Jeff

NPV Calculation - Non-Residential A-Line Lamp

year	Avoided capacity ($/kW-year) Generation	T&D	Saved Capacity kW/bulb	Generating Capacity Total $/bulb	T&D Capacity Total $/bulb	Total Capacity Saved Total $/bulb	Savings kWh/bulb	energy cost/kWh	Energy Savings $/bulb/year	# Bulbs	Capacity Total Program	Energy Savings	Program Costs
1	72.41	73.49	0.018716	$1.3552	$1.3754	$2.7307	89.065	0.02918	2.60	10333	$28,215.99	$26,854.51	$183,753.55
2	74.22	75.14	0.018716	$1.3891	$1.4063	$2.7954	89.065	0.02924	2.60	10333	$28,885.13	$26,909.73	
3	76.08	76.85	0.018716	$1.4239	$1.4383	$2.8622	89.065	0.02922	2.60	10333	$29,575.54	$26,891.32	
4	77.98	78.64	0.018716	$1.4595	$1.4718	$2.9313	89.065	0.02926	2.61	10333	$30,289.16	$26,928.14	
5	79.93	80.44	0.018716	$1.4960	$1.5055	$3.0015	89.065	0.03513	3.13	10333	$31,014.38	$32,330.33	
6	81.93	82.27	0.018716	$1.5334	$1.5398	$3.0732	89.065	0.03887	3.46	10333	$31,755.08	$35,772.27	
7	83.98	84.18	0.018716	$1.5718	$1.5755	$3.1473	89.065	0.04308	3.84	10333	$32,520.91	$39,646.76	
8	86.08	86.12	0.018716	$1.6111	$1.6118	$3.2229	89.065	0.04678	4.17	10333	$33,302.22	$43,051.89	
9	88.23	88.07	0.018716	$1.6513	$1.6483	$3.2996	89.065	0.0513	4.57	10333	$34,095.13	$47,211.67	
10	90.43	90.03	0.018716	$1.6925	$1.6850	$3.3775	89.065	0.05535	4.93	10333	$34,899.64	$50,938.90	
11	92.7	91.98	0.018716	$1.7350	$1.7215	$3.4565	89.065	0.05775	5.14	10333	$35,715.76	$53,147.64	
12	95.01	93.95	0.018716	$1.7782	$1.7584	$3.5366	89.065	0.06166	5.49	10333	$36,543.48	$56,746.03	
13	97.39	95.97	0.018716	$1.8228	$1.7962	$3.6189	89.065	0.06535	5.82	10333	$37,394.41	$60,141.96	
14	99.82	98.02	0.018716	$1.8682	$1.8345	$3.7028	89.065	0.06797	6.05	10333	$38,260.81	$62,553.16	
15	102.32	100.11	0.018716	$1.9150	$1.8737	$3.7887	89.065	0.0707	6.30	10333	$39,148.48	$65,065.59	
PV=				$14.15	$14.16	$28.30			34.64		$292,436.01	$357,921.52	$183,753.55
									PV Duke Calculations		$314,737.00	$428,762	
									Duke Calculations		Total NPV =	$743,499.00	
									NPV OUCC (less costs)		Total NPV =	$466,603.98	
									Per Bulb Shareholder Incentive			$7.20	
									Per Bulb Shareholder Incentive (less costs)			$4.52	

Coincident gross peak demand reduction = .0238 kW/bulb
NTG = 73.2%
Net demand impact = 0.0174216
Gross up for losses
-7.43% <u>0.018716025</u> kW/bulb

Gross Energy Savings/Bulb = 113.258 kWh/year

Cost/Bulb $15,009/844 bulbs = $17.78

NTG = 73.2%
Net energy impact = 82.90486
Gross up for losses <u>89.06469</u>
#NAME?

NPV Calculation - Non-Residential A-Line Lamp

year	Avoided capacity ($/kW-year) Generation	T&D	Saved Capacity kW/bulb	Generating Capacity Total $/bulb	T&D Capacity Total $/bulb	Total Capacity Saved Total $/bulb	Savings kWh/bulb	energy cost/kWh	Energy Savings $/bulb/year	# Bulbs	Capacity Total Program	Energy Savings	Program Costs
1			0.018716	$0.0000	$0.0000	$0.0000	89.065	0.02918	2.60	10333	$0.00	$26,854.51	$183,753.55
2			0.018716	$0.0000	$0.0000	$0.0000	89.065	0.02924	2.60	10333	$0.00	$26,909.73	
3			0.018716	$0.0000	$0.0000	$0.0000	89.065	0.02922	2.60	10333	$0.00	$26,891.32	
4	77.98		0.018716	$1.4595	$0.0000	$1.4595	89.065	0.02926	2.61	10333	$15,080.76	$26,928.14	
5	79.93		0.018716	$1.4960	$0.0000	$1.4960	89.065	0.0298452	2.66	10333	$15,457.88	$27,466.70	
6	81.93		0.018716	$1.5334	$0.0000	$1.5334	89.065	0.030442104	2.71	10333	$15,844.66	$28,016.03	
7	83.98		0.018716	$1.5718	$0.0000	$1.5718	89.065	0.031050946	2.77	10333	$16,241.12	$28,576.35	
8	86.08		0.018716	$1.6111	$0.0000	$1.6111	89.065	0.031671965	2.82	10333	$16,647.24	$29,147.88	
9	88.23		0.018716	$1.6513	$0.0000	$1.6513	89.065	0.032305404	2.88	10333	$17,063.04	$29,730.84	
10			0.018716	$0.0000	$0.0000	$0.0000		0.032951512	0.00	10333	$0.00	$0.00	
11			0.018716	$0.0000	$0.0000	$0.0000		0.033610543	0.00	10333	$0.00	$0.00	
12			0.018716	$0.0000	$0.0000	$0.0000		0.034282753	0.00	10333	$0.00	$0.00	
13			0.018716	$0.0000	$0.0000	$0.0000		0.034968409	0.00	10333	$0.00	$0.00	
14			0.018716	$0.0000	$0.0000	$0.0000		0.035667777	0.00	10333	$0.00	$0.00	
15			0.018716	$0.0000	$0.0000	$0.0000		0.036381132	0.00	10333	$0.00	$0.00	
PV=				$5.96	$0.00	$5.96			17.32		$61,542.66	$178,959.22	$183,753.55

Coincident gross peak demand reduction = .0238 kW/bulb
NTG = 73.2%
Net demand impact = 0.0174216
Gross up for losses
-7.43% 0.018716025 kW/bulb

NPV OUCC (less costs) Total NPV = $56,748.33

Per Bulb Shareholder Incentive (less costs) $0.55

Gross Energy Savings/Bulb = 113.258 kWh/year
NTG = 73.2%
Net energy impact = 82.90486
Gross up for losses 89.06469
-7.43%

Cost/Bulb $15,009/844 bulbs = $17.78

No Carbon Tax
No Avoided T&D Capacity

NPV Calculation - Non-Residential A-Line Lamp - All OUCC Recommended Adjustments

year	Avoided capacity ($/kW-year) Generation	T&D	Saved Capacity kW/bulb	Generating Capacity Total $/bulb	T&D Capacity Total $/bulb	Total Capacity Saved Total $/bulb	Savings kWh/bulb	energy cost/kWh	Energy Savings $/bulb/year	# Bulbs	Capacity Total Program	Energy Savings	Program Costs
1			0.018716	$0.0000	$0.0000	$0.0000	89.065	0.02918	2.60	10333	$0.00	$26,854.51	$183,753.55
2			0.018716	$0.0000	$0.0000	$0.0000	89.065	0.02924	2.60	10333	$0.00	$26,909.73	
3			0.018716	$0.0000	$0.0000	$0.0000		0.02922	0.00	10333	$0.00	$0.00	
4			0.018716	$0.0000	$0.0000	$0.0000		0.02926	0.00	10333	$0.00	$0.00	
5			0.018716	$0.0000	$0.0000	$0.0000		0.0298452	0.00	10333	$0.00	$0.00	
6			0.018716	$0.0000	$0.0000	$0.0000		0.030442104	0.00	10333	$0.00	$0.00	
7			0.018716	$0.0000	$0.0000	$0.0000		0.031050946	0.00	10333	$0.00	$0.00	
8			0.018716	$0.0000	$0.0000	$0.0000		0.031671965	0.00	10333	$0.00	$0.00	
9			0.018716	$0.0000	$0.0000	$0.0000		0.032305404	0.00	10333	$0.00	$0.00	
10			0.018716	$0.0000	$0.0000	$0.0000		0.032951512	0.00	10333	$0.00	$0.00	
11			0.018716	$0.0000	$0.0000	$0.0000		0.033610543	0.00	10333	$0.00	$0.00	
12			0.018716	$0.0000	$0.0000	$0.0000		0.034282753	0.00	10333	$0.00	$0.00	
13			0.018716	$0.0000	$0.0000	$0.0000		0.034968409	0.00	10333	$0.00	$0.00	
14			0.018716	$0.0000	$0.0000	$0.0000		0.035667777	0.00	10333	$0.00	$0.00	
15			0.018716	$0.0000	$0.0000	$0.0000		0.036381132	0.00	10333	$0.00	$0.00	
PV=				$0.00	$0.00	$0.00			4.69		$0.00	$48,487.36	$183,753.55

Coincident gross peak demand reduction = .0238 kW/bulb
NTG = 73.2%
Net demand impact = 0.0174216
Gross up for losses
-7.43% 0.018716025 kW/bulb

NPV OUCC (less costs) Total NPV = ($135,266.20)

Per Bulb Shareholder Incentive (less costs) ($1.31)

Gross Energy Savings/Bulb = 113.258 kWh/year

Cost/Bulb $15,009/844 bulbs = $17.78

NTG = 73.2%
Net energy impact = 82.90486
Gross up for losses 89.06469
7.43%

CERTIFICATE OF SERVICE

This is to certify that a copy of the ***OUCC Public Exhibit No. 1 Public (Redacted) Testimony of OUCC Witness John E. Haselden*** has been served upon the following parties of record in the captioned proceeding by electronic service on March 2, 2020.

Melanie Price
Andrew J. Wells
Nicholas K. Kile
Hillary J. Close
Duke Energy Indiana, LLC
melanie.price@duke-energy.com
andrew.wells@duke-energy.com
nicholas.kile@btlaw.com
hillaryclose@btlaw.com

Jennifer A. Washburn
Citizens Action Coalition
jwashburn@citact.org

Jeffrey M. Reed
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
PNC Center
115 West Washington Street
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