FILED
December 04, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF (1) AN ADJUSTMENT TO ITS RATES THROUGH ITS STANDARD CONTRACT RIDER NO. 66-A FOR DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAM COST RECOVERY, INCLUDING RECONCILIATION OF COSTS IN ACCORDANCE WITH THE FINAL ORDERS IN CAUSE NOS. 43955, 43955 DSM-1, 43955 DSM-2, 43955 DSM-3, 43955 DSM-4, 43955 DSM-5 AND 43955 DSM-6	)	**CAUSE NO. 43955 DSM 07**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

TESTIMONY OF

JOHN E. HASELDEN - PUBLIC'S EXHIBIT NO. 1

DECEMBER 4, 2019

Respectfully submitted,

Jeffrey M. Reed
Attorney No. 11651-49
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS JOHN E. HASELDEN
CAUSE NO. 43955 DSM-7
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: What is the purpose of your testimony?

A: I address whether Duke Energy Indiana, LLC's ("DEI") inputs to its shared savings incentive calculations are appropriate and recommend several revisions.

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 DR 4.2 and 4.3;
- Confidential Attachment JEH-2C, which contains Petitioner's confidential data response to CAC DR 3.6 (DSM-4);
- Attachment JEH-3, which contains a worksheet from Petitioner's Standard Contract Rider 50 filing submitted to the Commission on February 28, 2019;
- Attachment JEH-4, which is a recent photograph of general service halogen and LED light bulb displays, including pricing information;
- Attachment JEH-5, which contains excerpts from DEI's EM&V reports for the Energy Efficient Appliances and Devices Program and the Duke Energy Indiana Agency LED Program for the 2016-2017 program year.

- Attachment JEH-6, which contains a page from Cause No. 45253, Testimony of DEI witness John A. Verderame;
- Attachment JEH-7, which is the 2001 California Standard Practice Manual; and
- Attachment JEH-8, which are selected pages from The Northeast Energy Efficiency Alliance ("NEEA") publication, "Results of the 2018 Northwest Residential Lighting Long-Term Monitoring and Tracking Study. The full report is available at: https://neea.org/img/documents/Results-of-the-2018-Northwest-Residential-Lighting-Long-term-Montioring-and-Tracking-Study_190820_160415.pdf .

II. SHARED SAVINGS

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 provided to 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, and 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 is the formula for calculating the proposed shared savings financial incentive for DEI?

A: The formula used in this proceeding was approved in DEI's Cause No. 43955 DSM-4. As further explained on 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%

Q: Do you have any concerns regarding the method DEI used to calculate the DSM tracker adjustments proposed in this proceeding?

A: Yes. DEI used the correct accounting methodology to calculate the amounts shown in Confidential Exhibit 1-F (KKH). However, the inputs DEI used to calculate the Utility Cost Test ("UCT") are not correct.

Q: With what inputs do you take issue?

A: The OUCC takes issue with three aspects of DEI's UCT calculations:

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

2.) Avoided Transmission and Distribution ("T&D") capacity costs estimates included in the calculations are excessive (they should be zero), and

3.) Using halogen bulbs as the baseline to project future energy and demand savings.

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.[1] In addition, DEI will have an additional 100 MW of capacity available in 2021, which is currently under contract to another Indiana utility.[2] If made available to customers, this capacity could further delay the need for additional generating capacity beyond 2023. DEI did not make any capacity purchases in 2018 or 2019.[3]

DEI's UCT calculations should value avoided capacity at vero ($) for years 2018-2022. The confidential avoided costs used to calculate the benefit/cost ("B/C") tests in Cause No. 43955 (DSM-4) were originally provided in response to a data request by the Citizens Action Coalition in 2017 in that case.[4] These costs were also provided to the OUCC in this proceeding.[5] The costs are listed by year and are from DEI's 2015 IRP. The avoided capacity costs DEI used in its

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

[2] Attachment JEH-6, excerpt from Cause No. 45253, Testimony of DEI witness John A. Verderame, page 15, lines 3 and 4 of Petitioner's Exhibit 23.

[3] Attachment JEH-1, DEI's response to OUCC DR 1-6.

[4] Attachment JEH-2C, DEI response to CAC DR 3.6 in DSM-4.

[5] Attachment JEH-1C, DEI's response to OUCC DR 4.3

calculations are based upon the cost of a simple cycle combustion turbine escalated at an annual rate of 2.5%.[6] These are prices for supply-side capacity, should capacity be acquired in those years listed, and are not *avoided* capacity costs despite DEI labelling them as such. DEI assumed the supply-side cost of capacity in any year to be *avoided* capacity costs. Furthermore, DEI gave its DSM capacity savings full value in the current and subsequent years the DSM measures are implemented, even though DEI will not actually avoid any additional capacity costs until 2023 or later. This is an incorrect application. On page 23 of the 2001 California Standard Practice Manual ("CSPM")[7], benefits under the Program Administrator Cost Test, also known as the Utility Cost Test, 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.

The key words are "avoided supply costs." In terms of generating capacity for DEI, the avoided supply costs will not begin until 2023 or later, despite there being a demand reduction due to DSM efforts in 2018. 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},

[6] Attachment JEH-1, DEI's response to OUCC DR 4-5.

[7] Attachment JEH-7

uses the summation of <u>avoided</u> costs, UAC_t, discounted to the present (2018 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 values for UAC_t for years t=0 (2018) through 4 (2022) is zero for each year. Beginning in t=5 (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=5 through t=10. The second summation term of the formula applies to alternate fuels and does not apply to this discussion.

However, with the exception of general service lighting ("GSL") discussed below, the benefits of avoided <u>energy</u> are appropriately calculated by DEI for the entire life of the measure or program beginning in 2018, because the production costs of energy due to DSM are actually avoided in all years. A formula demonstrating this concept for avoided capacity appears in 170 IAC 4-4.1-9 (b). See also Attachment JEH-3.

DEI applies this concept to its annual avoided cost filings for its Standard Contract Rider 50. I have attached a sheet from its most recent filing wherein DEI discounts the value of capacity that would be paid to a qualifying facility in 2019 for capacity constructed in 2022.[8]

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[8] Attachment JEH-3

Q: What are the OUCC's issues with DEI's avoided T&D capacity costs?

A: Quantifying T&D capacity benefits created by DSM is difficult; in fact, such savings may not truly exist. T&D capacity benefits are created when they relieve specific circuits with capacity problems. 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 could 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 case.

In addition, DEI's values for avoided T&D capacity costs are not reasonable. As shown response to OUCC DR 4.5[9] and in the aforementioned 2017 confidential DR response to the CAC,[10] avoided T&D capacity costs are based upon DEI's expected T&D construction costs associated with load growth, divided by expected growth in peak load. This results in "avoided" T&D capacity cost estimates for 2018 which are 96% of estimated generation capacity.[11] DEI offers no evidence this method of estimating avoided T&D capacity costs relates to

[9] Attachment JEH-1, DEI's response to OUCC DR 4.5

[10] Attachment JEH-2C, DEI response to CAC DR 3.6 in DSM-4.

[11] Attachment JEH-1, Response to OUCC DR1.11

avoided T&D capacity costs caused by DSM programs. DEI is artificially inflating both its generating and T&D avoided capacity cost estimates.

Q: What is the effect of overstating avoided capacity costs?

A: The UCT calculation considers avoided capacity costs as a benefit to the programs. Therefore, the higher the avoided costs, the more it increases the calculated net present value ("NPV") of benefits. DEI takes a percentage of the NPV of benefits under the UCT as a shareholder incentive. Artificially inflating the UCT artificially inflates the incentive paid for by customers. DEI's calculation of the NPV benefit of capacity savings wrongly includes years when capacity is not needed (2018-2022). Avoided capacity costs for the years 2018 through 2022, and avoided T&D capacity costs for all years, should be valued at zero. The UCT calculations and subsequent shareholder incentive calculations should be recalculated using appropriate values, dates, and calculation methodology described above.

Q: What is the OUCC's concern with the extended application of halogen bulbs as a baseline for residential GSL measures?

A: DEI uses a 15-year life for calculating savings for a standard GSL A- Line LED bulb, compared to a baseline halogen bulb. For example, a 9-Watt LED bulb compared to a 43-Watt halogen bulb. DEI credits savings for standard LED lights delivered through its DSM programs for the full 15 years of the assumed life of the LED bulb, as measured against the halogen baseline. This 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, savings attributed to GSL LED bulbs delivered through DSM programs will cease within the next few years due to this changed baseline.

Q: What is your definition of a baseline for this particular measure?

A: 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;
2. Life of bulb;
3. Performance;
4. Warm-up time (in the case of CFL bulbs, there is often a delay in reaching full lumen output);
5. Waste heat (e.g., heat from lighting can increase air conditioning needs during warm weather);
6. 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);
7. General appearance;
8. Size;
9. Shape;
10. Fit in fixtures; and
11. Color rendering.

GSL LED bulbs have evolved and improved to rate high in most of the above considerations, including price. The Northeast Energy Efficiency Alliance

("NEEA") recently published its annual "Results of the 2018 Northwest Residential Lighting Long-Term Monitoring and Tracking Study."[12] 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-8. The market has moved this direction influenced by the impending backstop provisions of the Energy Independence and Security Act ("EISA") 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. This NOPR is not yet final. 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 conservatively estimate approximately 70-80% 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). Attachment JEH-4 is a picture I personally took showing packages of general service halogen bulbs next to LED

[12] Available at: https://neea.org/img/documents/Results-of-the-2018-Northwest-Residential-Lighting-Long-term-Montioring-and-Tracking-Study_190820_160415.pdf

bulbs on a major retailer's shelves.[13] A utility did not subsidize the pricing for these bulbs, and the retailer did not have them "on sale." While anecdotal, this is an easily observable change in the market. In the 2015 Indiana TRM, the incremental cost of an LED bulb was $30.41/bulb.[14] There has been a rapid and significant change in pricing in a market continuing to evolve. Recognizing the LED general service A-line bulb as the new baseline is the only reasonable alternative for GSLs.

Q: Do you have other comments regarding Attachment JEH-4?

A: Yes. The LED bulbs in the picture are not Energy Star bulbs. The packaging of the LED bulbs in the picture denote a 9-year life for the bulbs. Energy-Star bulbs usually have a longer life and cost more. The appropriate comparison for the non-Energy Star LED is to the halogen bulb alternative. Unsubsidized, the non-Energy Star LED purchase price is competitive with a halogen equivalent and is far more cost effective for customers in view of the fact a customer would need to purchase five halogens to obtain an equivalent life of an 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 not so relevant to some consumers, (because an LED, regardless of its Energy Star rating, has the best life-cycle cost).

However, DEI, is economically incented to subsidize or buy down the cost 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

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[13] Walmart, Avon, Indiana, (DEI territory) September 2019.

[14] Indiana Technical Reference Manual v 2.2, page 131.

and capacity for 15 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. If DEI's UCT calculations accounted for this market change, it would cost DEI millions of dollars each year in shareholder incentives and lost revenues but save customers much more. Most customers do not understand they pay for DSM subsidies whether they participate or not. 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.

Q: Do the EM&V reports make recommendations for GSLs?

A: Yes, on a limited basis. Because DEI does not complete annual reports for each program, the most recent residential lighting EM&V reports were completed in 2018 by Opinion Dynamics.[15] In the report, Opinion Dynamics recommends DEI adjust the installation trajectory to account for the EISA 2020 truncation. A 12-year measure life was recommended for the Free LED program, and a 5-year measure life was recommended for the Low Income Agency Assistance Program.

Q: Did Opinion Dynamics calculate benefit/cost test results for the programs?

A: No. Duke Energy corporate staff runs the DSMore model and calculates the benefit/cost test ratios and net present values for all DSM programs using separate proprietary software. The modeling, assumptions and calculations are not subject

[15] Attachment JEH-5

to independent review. As a result, there is no transparency and the modeling results cannot be replicated or verified by any other party.

Q: Has the OUCC discussed this issue of changing the baseline for GSLs with DEI?

A: Yes. I have discussed this topic with DEI for over a year in the context of DSM Oversight Board meetings; however, its position has not changed. DEI cites uncertainty concerning when the backstop provisions for EISA might be implemented and the current availability of halogen and incandescent bulbs. While I do not dispute the ability of the public to find and buy non-LED GSL bulbs, the point is the market for them continues to diminish and retail shelf space for non-LED GSL bulbs continues to shrink. I discuss the reasons for this in more depth below. DEI continues to ignore the easily observable market transformation and the consideration of factors that influence market acceptance of a new baseline. DEI and some EM&V evaluators continue to cling to the notion that a legal mandate is necessary to change the baseline, when it is not.

Q: What other sources of information have you reviewed that lead you to the conclusion that LED bulbs are, or soon will become the baseline for GSLs?

A: Other recognized and recent reference sources such as DOE's Uniform Methods Project (2017) ("UMP") and the Illinois Technical Reference Manual v8.0 (2019) address this issue. The UMP recommends setting a sunset date and cites states that have done so.[16] The Illinois Technical Reference Manual v8.0 states that lamps

[16] Uniform Methods Project Chapter 6, Section 4.3.2.

subject to the EISA backstop provision shall have a measure life of two years.[17] The primary take-away in this report regarding GSLs is market share of LEDs continues to grow rapidly, pricing has decreased significantly, and CFL's are almost gone from retail shelves.[18] This reflects trends anyone can observe in retail stores in Indiana as well.

Q: What impact does DEI's proposed use of halogen bulbs as a baseline for general service lighting have on the shared savings DEI seeks to recover in this proceeding?

A: In 2018, DEI distributed millions of LED light bulbs as replacements for GSLs through at least seven residential and commercial programs. DEI uses the estimated savings for these bulbs in the UCT calculations upon which shareholder incentives are based. As a benefit, DEI's calculation uses capacity and energy savings extrapolated for the estimated life of the LED - i.e., a full 15 years.[19] The avoided capacity costs are avoided only after 2023, and the avoided energy is experienced only until the LED baseline change in 2021. Because the shareholder incentive is a percentage of the NPV of the UCT, the shareholder incentive calculated by DEI is significantly overstated.

Q: Why is this problematic?

A: The assumption that savings will persist 15 years for this measure is inappropriate, because it is unlikely savings will be realized for more than the next few years as

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[17] See Illinois technical Reference manual Version 8.0, October 17, 2019, Volume 3, page 253 available at: https://www.icc.illinois.gov/programs/illinois-statewide-technical-reference-manual-for-energy-efficiency

[18] Attachment JEH-8, page 31 of the report.

[19] Tech-to-Tech meeting with Mr. Tom Wiles, October 17, 2019.

the market baseline for GSLs transitions to LED bulbs. However, because these "savings" are a basis for calculating shared savings financial incentives, DEI will recover these incentives from ratepayers in the next year with complete certainty and with no future true-up. Taken together with the excessive "avoided cost" of capacity issues identified earlier, if this is permitted, DEI will unreasonably collect millions each year going forward in excessive shareholder incentives.

An example is the shareholder incentive associated with the "free" light bulb program. DEI calculates the net present value of benefits using the UCT as \$11.91/bulb.[20] The shareholder incentive is therefore 10% of these benefits and equals \$1.191/bulb. DEI distributed 1,096,677 "free" bulbs.[21] Total shareholder incentive for 2018 for this one measure (9W GSL LED) in a subset of the residential lighting program is calculated to be \$1.3 million. The 9W GSL LED bulbs are included in at least six other programs and produce significant shareholder incentives as well.[22]

Q: What other costs are customers bearing with DEI continuing to distribute GSL LED bulbs?

A: DEI will continue to recover direct, indirect costs as well as lost revenues associated with this measure in 2018, 2019 and possibly 2020, if DEI's interim plan is approved. The OUCC is not recommending denying recovery of these costs. However, I point out that if the benefit/cost calculations were done properly, it is

[20] Attachment JEH-1, DEI response to OUCC DR 3.1(e)(ii).

[21] Attachment JEH-1, DEI response to OUCC DR 3.2(e)(ii).

[22] See footnotes 21 and 22.

likely these lighting measures would be found not cost effective, and the offering terminated. Consequently, residential customers would have saved millions each year net of the "free" LED bulbs some received.

Q: What does the OUCC recommend as a baseline for GSL bulbs?

A: The OUCC recommends DEI use LEDs as the baseline bulb with a sunset date for market baseline transformation effective January 1, 2021 to allow a burnout period for existing halogen bulbs. Said another way, this proposal would have no impact on lost revenues from bulbs being reconciled in this proceeding, nor any lost revenue impact for the lighting program in 2019 when that program year's costs are ultimately reconciled. All GSL bulbs with installation verified via EM&V prior to 1/1/20 would continue to earn lost revenues through 12/31/20 (the one year burn out period). However, GSLs installed on or after 1/1/20 would no longer be eligible for lost revenue recovery. No GSLs, regardless of installation date, would be eligible for lost revenues effective 1/1/21.

III. RECOMMENDATIONS

Q: Please summarize the OUCC's recommendations.

A: The OUCC recommends the Commission deny DEI's shared savings recovery request until DEI recalculates the UCT scores and shared savings amount using revised *avoided* costs properly applied and a January 1, 2020 effective date for considering LEDs as the baseline for programs containing general service lighting.

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 staff have 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 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 and 9), 43623 (DSM-19), 45086, 45145, 45193, 45194, 45235, 45245, 44733(TDSIC-5) and 44910 (TDSIC-4).

AFFIRMATION

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

John E. Haselden
Senior Utility Analyst
Indiana Office of Utility Consumer Counselor
Cause No. 43955 DSM-7

December 4, 2019
Date

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 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 provide a breakdown between generating capacity and T&D capacity.

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs incurred in 2018, not about programs to be offered in 2020-2023.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.2

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.

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs incurred in 2018, not about programs to be offered in 2020-2023.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.3

Request:

Are the avoided generating capacity costs provided in response to DR 1 above in market-based costs of capacity?

a. If not, what is the basis for the avoided capacity costs listed in response to DR 1?

b. What is the basis for avoided T&D capacity estimates?

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs incurred in 2018, not about programs to be offered in 2020-2023.

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Data Request Set No. 1
Received: October 21, 2019

OUCC 1.4

Request:

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

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: Duke Energy Indiana's most recent IRP shows a need for 100 MWs of solar capacity in 2023.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.5

Request:

Who was responsible for running the DSMore model?

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

Response:

Subject to and without waiving or limiting its response, Duke Energy Indiana responds as follows: 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-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.6

Request:

Did DEI make any capacity purchases in:

a. 2018?

b. 2019?

c. If yes, please provide a complete list of those purchases for each year.

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: Duke Energy Indiana did not make any capacity purchases in 2018 or 2019.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.7

Request:

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

a. 2020?
b. 2021?
c. 2022?
d. 2023?
e. If yes, please provide a complete list of planned purchase amounts for each year.

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs incurred in 2018, not about programs to be offered in 2020-2023.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.8

Request:

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

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: The discount rate for avoided capacity used in the DSMore model in this proceeding was 6.92%.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.9

Request:

Please provide the formulae by which avoided capacity benefits for a DSM measure with 1 kW of net impact and a 5 year life installed in 2018 are calculated.

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018. Duke Energy Indiana further objects to this request as vague and ambiguous. Finally, Duke Energy Indiana objects to this request as it request a calculation that has not been performed and to which Duke Energy Indiana objects to performing.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.10

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 requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.11

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
b. t=2
c. t=3
d. t=4.

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

Response:

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

a. t=1, Year = 2018 – Avoided Generation Capacity = $71.04/KW-year, Avoided T&D = $68.16/KW-year.
b. t=2, Year = 2019 – Avoided Generation Capacity = $72.82/KW-year, Avoided T&D = $70.22/KW-year.
c. t=3, Year = 2020 – Avoided Generation Capacity = $74.64/KW-year, Avoided T&D = $71.90/KW-year.
d. t=4, Year = 2021 – Avoided Generation Capacity = $76.51/KW-year, Avoided T&D = $73.49/KW-year.

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[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-7
Data Request Set No. 1
Received: October 21, 2019

OUCC 1.12

Request:

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

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 3
Received: October 29, 2019

OUCC 3.1

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 2018:

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. $26.44

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

d. $23.84

e. i. $10.55
   ii. $11.91
   iii. $10.91

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. Exterior - $38.25; Interior - $87.83

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 3
Received: October 29, 2019

OUCC 3.2

Request:

Please provide the number of 9W standard A-Line light bulb measure distributed in the following programs in 2018:

a. Energy Education Program for School
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. Energy Education Program for Schools: Participation is based on total Energy Efficiency Kit and not broken out separately by measure in annual filings.

b. Multifamily EE Products and Services: 8,744 bulbs

c. Residential Energy Assessments: Participation is based on total Energy Efficiency Kit and not broken out separately by measure in annual filings.

d. Residential Energy Assessments – Extra Bulbs: 0

e. Smart Saver Residential (Lighting)
    i. Online Saving Store: 10,068 bulbs
    ii. Free lighting: 1,096,677 bulbs
    iii. Retail lighting: 104,622 bulbs

f. Small Business Energy Saver: 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. Smart Saver Non-Residential (Prescriptive): 10,349 bulbs

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 3
Received: October 29, 2019

OUCC 3.3

Request:

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

a. 2018
b. 2019

Objection:

Duke Energy Indiana objects to this requests on the grounds that the information sought is neither relevant nor admissible as it is beyond the scope of Duke Energy Indiana's case-in-chief testimony; further, it is not reasonably calculated to lead to the discovery of admissible evidence. This proceeding is about the reconciliation of costs previously approved and incurred in 2018.

Response:

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

a. The table below indicates the average costs for the Residential Smart $aver program for 2018. The average incentive is the bulb only and overall includes implementation and shipping.

Residential Smart $aver	Average Incentive $	Average Overall Costs
Online Store	$ 2.00	$ 2.00
Free	$ 2.67	$ 3.25
Retail	$ 2.47	$ 2.99
Total Lighting	$ 2.65	$ 3.22

b. See objection above.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 3
Received: October 29, 2019

OUCC 3.4

Request:

Please provide workpapers and calculations, by measure, supporting the UCT Net Benefits shown on Confidential Exhibit 1-F (KKH) for:

a. Small Business Energy Saver Program for 2018
b. Smart Saver Non-Residential Program for 2018

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. Duke Energy Indiana also objects to this request to the extent it purports to require Duke Energy Indiana to supply information in a format other than the format in which Duke Energy Indiana keeps such information. Duke Energy Indiana further objects to this request as overly broad and unduly burdensome.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: Duke Energy Indiana does not calculate "UCT Net Benefits" for the requested two (2) programs at the measure level; and as such, cannot provide such information.

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 4
Received: November 20, 2019

OUCC 4.1

Request:

Please provide the number of standard A-Line light bulb measures included in each energy efficiency kit used in the following programs in 2018:

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

Response:

a. Energy Education Program for Schools kits - 2
b. Residential Energy Assessments - 2

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 4
Received: November 20, 2019

OUCC 4.2

Request:

Please provide workpapers and calculations, by measure, supporting the avoided costs shown on Confidential Exhibit 1-F (KKH) for:

a. Small Business Energy Saver Program for 2018 ($14,378,749)
b. Smart Saver Non-Residential Program for 2018 ($52,700,012)

Response:

See Duke Energy Indiana's Confidential Attachment OUCC 4.2-A.

Witness: Karen K. Holbrook

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 4
Received: November 20, 2019

OUCC 4.3

Request:

Please provide the annual avoided capacity cost inputs used in the DSMore model for calculation of the UCT and TRC tests for the 2018 DSM programs. Please also provide the breakdown between generating capacity and T&D capacity.

Response:

See Duke Energy Indiana's Confidential Attachment OUCC 4.3-A.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 4
Received: November 20, 2019

OUCC 4.4

Request:

Please provide the annual avoided energy cost inputs used in the DSMore model for calculation of the UCT and TRC tests for the 2018 DSM programs. If a line loss factor is included, please provide the factor and the supporting analysis.

Response:

See Duke Energy Indiana's Confidential Attachment OUCC 4.3-A.

A line loss factor of 8.0264% was applied to all KW and KWh savings. The line loss factor was provided by the Company's Rate department and was calculated using actual retail generation versus metered sales in the Company's last approved rate case.

OUCC
IURC Cause No. 43955 DSM-7
Data Request Set No. 4
Received: November 20, 2019

OUCC 4.5

Request:

Are the avoided generating capacity costs in Question 3 above market-based costs of capacity?

a. If not, what is the basis for the avoided capacity costs listed in response to Question 3 above?
b. What is the basis for avoided T&D capacity estimates?

Response:

Yes.

a. Avoided Capacity costs are based on the cost of building a peaker provided by the Company's IRP group in the 2015 IRP. These costs have been escalated by 2.5% per year as directed by the Company's IRP group. These values are the same as approved in the initial filing of the 2017 - 2019 portfolio in Cause 43955 DSM-4.

b. The Avoided T&D values were provided by the Company's Rates group and are based on a study of T&D investments required to accommodate load growth. These costs were provided in 2016 dollars and then escalated into future years using the Handy Whitman Electric Plant Forecast index. These values are the same as approved in the initial filing of the 2017 - 2019 portfolio in Cause 43955 DSM-4.

Cause No. 43955 DSM-7
CONFIDENTIAL
OUCC Attachment JEH-1C

Cause No. 43955 DSM-7
CONFIDENTIAL
OUCC Attachment JEH-2C

Received: February 25, 2019
IURC 30-Day Filing No.: 50252
Indiana Utility Regulatory Commission

James Riddle
Rates & Regulatory Strategy Manager
Duke Energy Ohio, LLC
139 East Fourth Street
Cincinnati, OH 45202
513-287-2386
513-287-2466 fax
Jim.riddle @duke-energy.com

February 28, 2019

Secretary of the Commission
Indiana Utility Regulatory Commission
101 W. Washington St.
Suite 1500 East
Indianapolis, IN 46204-3407

Dear Secretary:

Duke Energy Indiana, LLC hereby submits, in accordance with 170 IAC 1-4-4.1-10, for review and approval under the Commission's thirty-day filing procedure, Standard Contract Rider No. 50 – Parallel Operation for Qualifying Facility.

Standard Contract Rider 50 shows Duke Energy Indiana's standard offer energy and capacity rates for 2019 for a qualifying facility. As per the Commission, under 170 IAC 1-6-3, Section 3-6, this filing should be made under the thirty-day filing procedure.

Attached are the working papers that show the development of the standard offer energy and capacity rates for 2019. This filing reflects the capital structure and current cost rates as of December 31, 2018. It also reflects the cost of common equity rate approved by the Commission in Cause No. 42359. The energy rate was developed utilizing a Planning and Risk (PaR) model version 6.1 simulation run that treats the 100 MW decrement as a dispatchable non-firm, external purchase. Thus, the marginal energy cost savings is the replacement cost for the 100 MW purchase. This cost includes fuel, fuel handling, variable O&M related to energy, effluent values and fuel auxiliary costs. Generator start-up cost have been included.

The marginal energy cost shows little change from the prior year. A 214.5MW combustion turbine is used as the 2019 standard offer capacity rate. We have compared this to a 214.5 MW combustion turbine with an in-service date of 2022.

We are filing Rider 50 and all associated work papers, including the Company's verified statement that we have provided or will provide notice to our customers as required under Section 6 of the thirty-day filing rules, electronically. We would appreciate the return of a file-stamped copy for our files.
If there are any questions concerning this filing, please contact me at 513.287.2386.

DUKE ENERGY INDIANA, LLC
2019 COGENERATION FILING
CALCULATION OF STANDARD OFFER RATE
FOR THE PURCHASE OF CAPACITY

FOR 2022 214.5 MW Combustion Turbine Unit

RATE FOR THE PURCHASE OF CAPACITY

$$C = 1/12 * [(D * V * F * ((1+Ip)^{\wedge(t-1)})) + (O * ((1 + Io)/(1+r)) * ((1 + Io)^{\wedge(t-1)}))] / (1 - L/2)$$

= \$4.60 PER KW PER MONTH

$$Ca = C * (((1 + Ip)/(1 + r))^{\wedge(Yi-Yc)})$$

= \$3.97 PER KW PER MONTH

WHERE:

D =	1.15362
V =	\$635 PER KW (2019 \$)
F =	0.058462 (Based on formula contained in 170 IAC 4-4.1-9)
Ip =	2.50%
Io =	2.50%
O =	\$8.73 PER KW (2019 \$)
r =	7.67%
n =	35
L =	5.3440042%
t =	3
Yi =	2022 (In service year of CT)
Yc =	2019 (Current year)

NOTE : (a) Investment cost based on a 214.5 MW combined cycle unit with a 2022 in service date.
(b) Escalation rates is standard rate used in model.


9/25/19
LED
GENERAL PURPOSE
Great Value
60
SOFT WHITE
$9.97
$10.88
$10.88
$4.24
$1.24
$7.97
$2.97
2X LIFE
Energy Saver
Halogen Bulbs
12 Light Bulbs
4 Light Bulbs
lasts 1.8 years
4 BULBS

2.9 Summary Form

DEI Free LED Program

Completed EMV Fact Sheet

Duke Energy Indiana's Free LED program is a continuation of the Free CFL program. The transition from CFLs to LEDs occurred in June 2016. Select eligible customers received a business reply card (BRC) in the mail to redeem for a free kit with six 9-watt LEDs. Eligible customers have been limited to DEI electric customers who had not reached the Duke Energy free bulb limit of 15-. To better manage program budgets, program marketing and outreach have been limited to business reply cards (BRCs), which has been the only means of program participation as well.

Date	June 8, 2018
Region(s)	Duke Energy Indiana
Evaluation Period	June 14, 2016 through January 18, 2018
Gross Annual MWh impact	46,314 MWH 71% realization rate
Coincident MW impact	3.64 MW (summer) 57% realization rate (summer) 6.32 MW (winter) 104% realization rate (winter)
Measure life	12 years
Net to Gross	58.5%
Process Evaluation	Yes
Previous Evaluation(s)	None

Evaluation Methodology

The evaluation team reviewed reported savings assumptions to ensure that the inputs used to calculate those assumptions were in line with the previous evaluation's recommendations. The evaluation team also performed an engineering analysis of energy and demand savings to develop ex post savings estimates, including estimation of a net-to-gross ratio (NTGR) and first-year in-service rate (ISR) through a participant survey. The evaluation team also conducted a program process evaluation including results from a participant survey.

Impact Evaluation Details

- The evaluation team relied on the Uniform Methods Project (UMP) recommended approach to estimate gross energy and peak demand savings, and incorporates additional adjustments as necessary.
- The evaluation team estimated baseline wattages using the equivalent baseline wattage approach with consideration of applicable federal efficiency standards (e.g., EISA).
- The evaluation team estimated hours of use (HOU) and peak coincidence factors (CFs) from a long-term metering effort in the DEI jurisdiction.
- The evaluation team relied on a participant research to estimate first-year in-service rate (ISR) and net-to-gross ratio (NTGR).
- The evaluation team used a discounted approach to claiming savings from future installations of LEDs distributed by the program during the evaluation period. The approach involves claiming savings from all expected installations in the program year but discounting them by a utility discount rate. The evaluation team incorporated the UMP recommended future installation trajectory and truncation of future savings post-EISA 2020 standards.

10. Summary Form

DEI Low Income Agency Assistance

Completed EMV Fact Sheet

The Agency Assistance program provides free kits of 12 9-watt LED bulbs to income-qualified residential customers in DEI service territory. The program began offering LEDs in September 2016, before which a kit of 12 free CFLs was offered. Duke Energy implements the program with the assistance of state and regional poverty relief agencies as they administer the U.S. Department of Health and Human Services' Low Income Home Energy Assistance Program (LIHEAP).

Date	June, 2018
Region(s)	Duke Energy Indiana
Evaluation Period	January 1, 2016 – December 31, 2017
Total kWh Savings	1,424,570 kWh
Coincident kW Impact	Summer: 176.4 kW Winter: 236.5 kW
Measure Life	5 years
Net-to-Gross Ratio	N/A
Process Evaluation	Yes
Previous Evaluation(s)	April 2014, November 2016

Evaluation Methodology

The evaluation team verified deemed savings estimates for measures using an engineering analysis of savings assumptions and calculations. The evaluation team also leveraged a participant survey to verify ISRs for LEDs and collect information on household characteristics to inform the engineering analysis.

Impact Evaluation Details

- Duke Energy customers who qualify for LIHEAP and have not already participated in the DEI Agency Program or received lighting from other DEI programs are eligible for enrollment.
- Kits are mailed to customers by AM Conservation after participant lists are reviewed by IHCDA and Duke Energy staff.
- Each kit currently includes twelve 9-watt LEDs. CFL kits were provided up to September 2016 and contained six 13-watt CFLs and six 18-watt CFLs.
- Results from the participant survey and review of secondary research informed an engineering review of LED savings assumptions associated with measures provided. The team applied existing deemed savings values for CFLs established in the evaluation of the 2015 program.
- The engineering analysis applied deemed savings values to measures distributed and in service.
- Process analysis of program-tracking data shows that about 8% of participants received lighting from at least one of five other Indiana programs (n=4,770), including DEI and IN-CORE programs.

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. NON-NATIVE SHARING PROPOSAL

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.

CALIFORNIA STANDARD PRACTICE MANUAL

ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

OCTOBER 2001

Table of Contents

Page

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

Primary	Secondary
Participant	
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 ($NPVp \geq 0$ and $BCRp \geq 1.0$) 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.)

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

<u>Where</u>:

[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.

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[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

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:

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

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

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

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

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

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,

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

August 20, 2019

REPORT # E19-389

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

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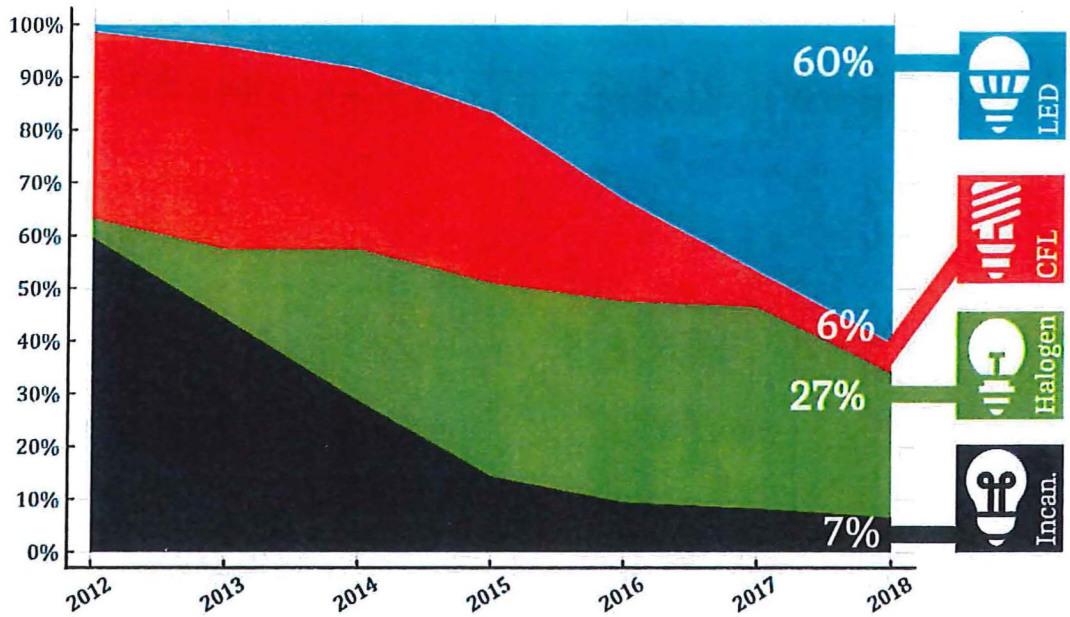
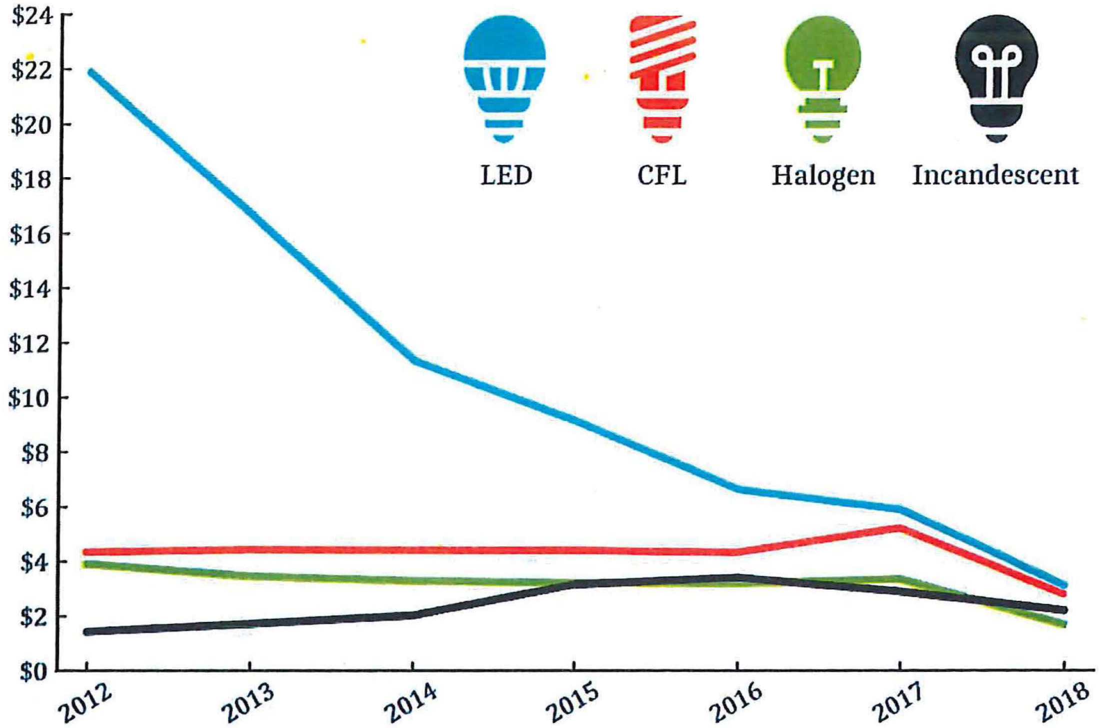
Figure 3. General Purpose Lamps - Technology Shares, 2012-2018



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

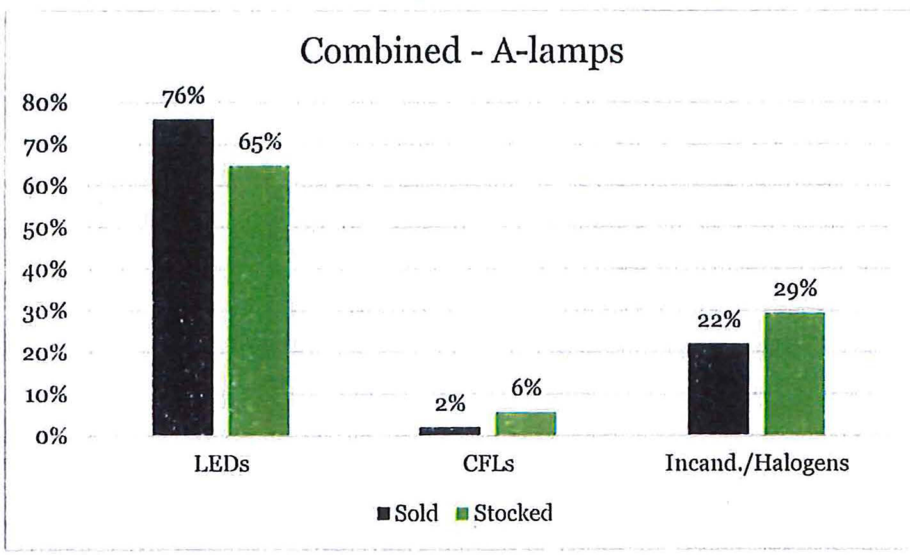


Table 13 and Figure 18 show the average of the estimated percentages of A-lamps sold provided by DIY store managers compared to the unweighted percentage of A-lamps observed in those stores by field staff, by lamp technology.

CERTIFICATE OF SERVICE

This is to certify that a copy of the ***OUCC TESTIMONY OF JOHN E. HASELDEN*** has been served upon the following parties of record in the captioned proceeding by electronic service on December 4, 2019.

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