COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN	))))))))	**CASE NO. 2022-00402**

DIRECT TESTIMONY OF
LANA ISAACSON
MANAGER, EMERGING BUSINESS PLANNING AND DEVELOPMENT
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 15, 2022

INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Lana Isaacson. I am the Manager of Emerging Business Planning and Development for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company ("LKS"), which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your educational and professional background.

A. I have a bachelor's degree in Mechanical Engineering from the University of Iowa and have worked in the utility industry for nearly 30 years. I have been employed by LKS since 2019 and began as a Senior Key Account Manager. I was promoted to my current role in November 2021. In my current role as Manager of Emerging Business Planning and Development, I am responsible for overseeing the development of new programs and services for residential, commercial, and industrial customers. My team and I identify potential new programs or services through market research, peer collaboration, and from attending professional conferences. In addition, my team provides guidance on the marketing strategies for the Companies' programs and services. A complete statement of my work experience and education is contained in Appendix A attached to my testimony.

Q. Have you previously testified before the Commission?

A. No, but I have assisted with preparing responses to requests for information and reports to the Kentucky Public Service Commission ("Commission") and the Virginia State Corporation Commission in previous rate cases and integrated resource plan cases.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe the analysis that led to the Companies' proposed 2024-2030 Demand-Side Management and Energy Efficiency Program Plan ("Proposed DSM-EE Program Plan"). I describe the processes and studies the Companies used to evaluate the Companies' DSM-EE programs, determine the potential DSM-EE opportunities in the Companies' services territories, and develop the Proposed DSM-EE Program Plan.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am co-sponsoring Exhibit JB-1, the Proposed DSM-EE Program Plan, which discusses the historical performance of the Companies' DSM-EE programming, describes the process by which the Companies developed the Proposed DSM-EE Program Plan, and presents the analyses supporting the plan. I am co-sponsoring this exhibit with John Bevington.

I am also sponsoring the following exhibits:

- Exhibit LI-1: *2022 Cross-Sector DSM Potential Study Projection*
- Exhibit LI-2: *2023 LG&E and KU Demand Response Assessment*
- Exhibit LI-3: Supporting Calculations for KU DSM Cost Recovery Mechanism
- Exhibit LI-4: Supporting Calculations for LG&E Electric DSM Cost Recovery Mechanism
- Exhibit LI-5: Supporting Calculations for LG&E Gas DSM Cost Recovery Mechanism
- Exhibit LI-6: Proposed DSM-EE Program Plan Workpapers

POTENTIAL STUDIES

Q. Please describe the studies the Companies commissioned to understand the market potential for energy-efficiency programming in their service territory.

A. The Companies commissioned their DSM-EE consultant, The Cadmus Group, Inc. ("Cadmus") to update a residential and commercial potential study and an industrial potential study Cadmus performed in 2017 and 2016, respectively. The *2022 Cross-Sector DSM Potential Study Project* updates the *Residential and Commercial Energy and Efficiency Potential Study* presented in Case No. 2017-00441 for the period of 2019 to 2038 and the *Industrial Energy and Efficiency Potential Study* ordered by the Commission in Case No. 2014-00003 for the period of 2016 to 2035. The *2022 Cross-Sector DSM Potential Study Project* explores the potential of energy efficiency programming in the Companies' service territory and quantifies the amount of energy and demand that could be saved in the Companies' service territory from 2024 through 2043.

Cadmus also prepared the *2023 LG&E and KU Demand Response Assessment* for the Companies' 2021 IRP case, Case No. 2021-00393. The *2023 LG&E and KU Demand Response Assessment* updates the 2017 residential and commercial study and 2016 industrial study to examine demand response potential on a 20-year planning horizon from 2023 through 2042.

These studies focus primarily on efficiency technologies and practices widely available at the time of the assessment, while accounting for known changes in codes and standards, technical limitations, total resource cost effectiveness, and customers' willingness to adopt efficiency measures. For instance, the Department of Energy issued new rulings in April 2022 that require lighting products to meet new standards.

As a result, the baseline for determining potential is now LEDs, and no screw base lighting potential was included in the analysis for 2024-2043. The updates to the potential values attempt to account for relevant inputs including the most recent changes to federal lighting and energy efficiency standards, as well as the effects of the federal Inflation Reduction Act.

Q. Please briefly describe the results of the most recent potential study and the impact on future energy-efficiency programming by the Companies.

A. As the Companies expected, the *2022 Cross-Sector DSM Potential Study Projection* showed that the potential for energy efficiency has declined. Comparing the results from the potential studies the Companies performed in 2016 and 2017 to the 2022 study shows that cumulative electric energy-savings technical potential has declined by approximately 12% over the 20-year study horizon in the five years since the previous studies were completed.

The following table summarizes the results of the *2022 Cross-Sector DSM Potential Study Projection* compared to the prior potential studies:

Medium Scenario – 20-year Cumulative Achievable Potential	**Residential**	**Commercial**	**Industrial**
Study Period	2024-2043	2024-2043	2024-2043
Energy (% of Baseline)			
LG&E & KU	2.9%	5.3%	6.5%
LG&E Gas	5.0%	4.1%	6.1%
Demand (MWs)			
LG&E & KU	54	94	73
Study Period	2019-2038	2019-2038	2016-2035
Energy (% of Baseline)			
LG&E & KU	5.5%	6.1%	6.7%
LG&E Gas	6.7%	5.2%	6.0%
Demand (MWs)			
LG&E & KU	74	112	74

The *2022 Cross-Sector DSM Potential Study Projection* indicates that there are theoretically cumulative achievable DSM-EE demand and energy savings in the Companies' energy efficiency portfolio of 221 MW, 1,471 GWh, and 1,331,762 Mcf by 2043.

Q. Did the potential studies provide any insight concerning whether it is economically possible to offset the Companies' capacity needs with DSM-EE?

A. Yes. The *2022 Cross-Sector DSM Potential Study Project* calculates the potential of energy efficiency programming by analyzing the technical, economic, and achievable potential. The technical potential represents all technically feasible energy efficiency measures being implemented, regardless of their costs or market barriers. Economic potential is a subset of technical potential, comprising only measures meeting cost-effectiveness criteria based on the Companies' avoided supply costs. Even the identified economic potential would fail to meet the Companies' capacity shortfall.

PROPOSED DSM-EE PROGRAM PLAN

Q. With the Companies' Proposed DSM-EE Program Plan, are the Companies on track to attain the potential identified in the potential studies?

A. Yes. The Proposed DSM-EE Program Plan will allow the Companies to reach their program DSM-EE potential while remaining cost-effective at the portfolio level.

Q. What programs are the Companies proposing in the Proposed DSM-EE Program Plan?

A. For the 2024-2030 period, the Companies are proposing energy efficiency programs, demand response programs, and one administrative program. The energy efficiency programs include: Income-Qualified Solutions, Appliance Recycling, Residential Online Audit, and Business Solutions. The demand response programs include:

Connected Solutions, Peak Time Rebates, and Nonresidential Demand Response. The administrative program is Program Development and Administration, which captures costs incurred in developing and administering energy efficiency initiatives that are difficult to assign to an individual program. I describe each of the energy efficiency and demand response programs in more detail below.

Q. Please describe Income-Qualified Solutions.

A. Income-Qualified Solutions helps customers who are at or below 300% of the federal poverty level to lower their energy bills. This program consists of two subcomponents: Low-Income Weatherization (formerly known as WeCare) and Whole-Building Multifamily. The Low-Income Weatherization subcomponent is an education and weatherization program designed to reduce energy consumption of income-qualified customers. It provides energy audits, energy education, and installation of weatherization and energy conservation measures in qualified single-family homes. The Companies propose to expand the successful WeCare program in a number of meaningful ways to reach more customers, including expanding the eligibility to serve customers who are at or below 300% of the federal poverty level, including a smart thermostat direct install measure, using publicly available data to better target eligible customers, promoting the program services in high-need areas, and increasing the overall average allowable measure cost per single-family home to a larger group of eligible customers.

The Whole-Building Multifamily subcomponent will expand upon the current WeCare offering by providing multifamily property managers and owners with various tools for increasing the efficiency of their income-qualified properties' common areas and tenant units. These tools include: direct installation of various energy-saving devices; incentives to property managers and owners who purchase high-efficiency equipment to retrofit the property as a whole; and energy usage and conservation education. The Income-Qualified Solutions program includes Inflation Reduction Act consultation to educate various stakeholders and participants about the future options made available through this legislation.

Q. Please describe Appliance Recycling.

A. The Appliance Recycling Program offers residential customers an opportunity to safely dispose of and recycle inefficient but working refrigerators and freezers and receive a one-time incentive for doing so. Small nonresidential customers with residential-size appliances may also qualify for the program. The program includes the option to recycle a working room air conditioner or dehumidifier if already recycling a working refrigerator or freezer. The Companies plan to work with an independent third-party vendor to collect and transport working but inefficient appliances to an appropriate recycling center that is responsible for adhering to local, state, and federal recycling ordinances. The program will reduce energy consumption and demand as well as the burden on Kentucky landfills by enabling the safe disposal of hazardous chemicals.

Q. Please describe Residential Online Audit.

A. The Residential Online Audit Program is a web-based, self-guided assessment of a customer's home and includes information about the home's space and water heating, appliance and plug load, and other energy end uses. The audit pulls customer-specific interval data from the Companies' advanced metering infrastructure ("AMI") to provide an accurate picture of the customer's disaggregated energy use. After completing the online audit, customers receive feedback on their energy-use behavior, energy-saving tips, and recommendations. Participants are mailed a kit including energy efficiency measures for self-installation. Customers who complete the audit gain access to prescriptive rebates received from the installation of energy efficient measures in the home. The purpose of the program is to provide both education and incentives for energy efficient equipment intended for energy savings.

Q. Please describe Business Solutions.

A. Business Solutions seeks to reduce energy consumption in the nonresidential sector while providing easy participation options for businesses of any size. Business Solutions has three subcomponents: Nonresidential Rebates, Small Business Audit and Direct Install, and Nonresidential Midstream Lighting. These programs build upon the successful existing Nonresidential Rebates Program by building two new subcomponents and removing the program participation cap for the Nonresidential Rebates Program to encourage a wider range of customer participation and energy efficiency project savings potential.

Through the Nonresidential Rebates subcomponent, the Companies provide nonresidential customers with financial incentives to help replace aging and inefficient equipment. The Small Business Audit and Direct Install subcomponent provides in-person energy audits to small businesses and provides free direct installation of energy-saving products that may include LED bulbs and fixtures, faucet aerators, low-flow showerheads, and pre-rinse spray valves. The Nonresidential Midstream Lighting subcomponent provides incentives to lighting distributors to stock and sell high-efficiency equipment and then pass on the incentive to the customer at the time of purchase. This program subcomponent is designed to encourage distributors to stock and sell high-efficiency equipment models and provide the incentive to customers in a quick, easy manner.

Q. Please describe Connected Solutions.

A. Through Connected Solutions, the Companies will provide opportunities for residential and small business customers to reduce demand during summer and winter peak periods. This new umbrella program includes the program currently known as the Residential and Small Nonresidential Demand Conservation Program (Direct Load Control ("DLC")) and three new subcomponents: Bring-Your-Own Device ("BYOD"), Optimized Charging, and Online Transactional Marketplace. The Companies will continue DLC for current participants, though participation will decrease over time as switches fail. As switch failures occur, the Companies will direct customers to other demand response offerings.

The BYOD subcomponent is an event-based, load control resource that enables the Companies to directly manage summer and winter loads during hours of peak demand through smart thermostats and other devices without the need for switches. Participating customers are rewarded for each event they participate in and for each device enrolled in the program. The Optimized Charging subcomponent allows the Companies to issue signals to qualifying electric vehicles ("EV") and qualifying EV supply equipment to affect the timing and level of EV charging as a means of active, targeted load management. The participating customer receives an incentive each month. This subcomponent will be available to residential customers that are not on time-of-day rates. The Online Transactional Marketplace subcomponent offers customers discounted smart thermostats and smart plugs with a link to directly enroll into the BYOD program.

Q. Please describe Peak Time Rebates.

A. Peak Time Rebates is a voluntary, event-based demand response resource that rewards customers who successfully reduce their electric consumption during periods of high demand throughout the year. The Companies will notify customers in advance of peak demand events and educate customers on ways to save and shift energy consumption during events. Peak Time Rebates requires the Companies' AMI data to enable the pay-for-performance incentive model and calculate customers' kWh savings during events. In the past, the Companies could not pursue Peak Time Rebates because they did not have AMI, but with the planned rollout completion of AMI during this portfolio period, Peak Time Rebates can be deployed to customers beginning in 2025.

Q. Please describe Nonresidential Demand Response.

A. Nonresidential Demand Response is the new name for the expanded Large Nonresidential Demand Conservation Program. The Companies will continue to provide load monitoring devices to help business customers make changes to their operational procedures that reduce demand during peak times. The Companies propose to modify the program by increasing marketing activities to recruit more customers and increasing the incentive from $15 to up to $75 per kilowatt curtailed.

Q. Will the Companies continue to evaluate the naming of the proposed programs in the DSM-EE Program Plan?

A. Yes, the Companies plan to evaluate the naming of the programs for marketing purposes. The names of the programs may change. If they do, the Companies will submit an informational filing notifying the Commission of any change.

Q. Will the Companies allow customers to participate in multiple programs in the Proposed DSM-EE Program Plan?

A. Yes, with limited exceptions, the Companies plan to allow customers to participate in multiple programs and will use software to manage enrollment, accurately calculate savings, and issue incentives to customers enrolled in multiple programs. The software must be capable of adjusting for customer participation in multiple programs to avoid compensating a customer more than once for the same demand reduction. The Companies have met with software vendors that have confirmed that such software is commercially available from multiple vendors. For instance, the software would ensure that customers participating in the Peak Time Rebates program and in the Demand Conservation subcomponent with air conditioners would have their Peak Time Rebate event energy savings reduced by any energy savings attributable to the air conditioner response during an overlapping Demand Conservation event. In the unlikely event that the Companies are unable to implement software with capabilities to accurately calculate savings, the Companies will limit customer participation between multiple programs for like equipment, as needed, to ensure savings and incentives are calculated accurately.

Even with the implementation of software, there are limited circumstances when the Companies must restrict customer participation in multiple programs for like equipment to prevent double compensation. For instance, a customer enrolled in

Demand Conservation for an air conditioning unit may not also enroll in BYOD to manage the same load through a smart thermostat. In those limited circumstances, the Companies' tariffs limit participation in multiple programs when software is unable to prevent compensating a customer more than once for the same demand reduction.

Q. Does the Proposed DSM-EE Program Plan provide DSM-EE opportunities for large customers?

A. Yes. The Proposed DSM-EE Program Plan expands the DSM-EE offerings for large customers. Specifically, the Nonresidential Rebates subcomponent of Business Solutions includes revised incentives to prioritize demand reduction and removes the program's incentive cap (previously $50,000 annually and $100,000 in total) to encourage larger businesses to participate, specifically industrial customers who may have previously opted out of DSM-EE. The Companies hope these changes will make DSM-EE more attractive to large customers and encourage more participation.

Q. Do the Companies use cost-benefit tests to help determine which DSM-EE programs to propose to implement?

A. Yes, the Companies rigorously analyze existing and potential DSM-EE programs using the industry-standard cost-benefit tests set out in the California Standard Practice Manual,[1] which the Commission has required utilities to apply for almost 20 years: "Any new DSM program or change to an existing DSM program shall be supported by . . . [t]he results of the four traditional DSM-EE cost-benefit tests [Participant, Total

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[1]The Manual is available online at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf.

Resource Cost, Ratepayer Impact, and Utility Cost tests]."[2] The Manual defines the four tests as follows:

- **The Participant Test ("PCT")**: 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.[3]

- **The Ratepayer Impact Measurement Test ("RIM")**: The Ratepayer Impact Measure [] 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.[4]

- **Total Resource Cost Test ("TRC")**: 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. . . . 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 Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).[5]

- **The Program Administrator Cost Test ("PAC" or "Utility Cost Test")**: 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.[6]

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[2] *See Joint Application of the Members of the Louisville Gas and Electric Company Demand-Side Management Collaborative for the Review, Modification, and Continuation of the Collaborative, DSM Programs, and Cost Recovery Mechanism*, Case No. 1997-00083, Order at 20 (Ky. PSC Apr. 27, 1998).
[3] Manual at 8.
[4] Manual at 13.
[5] Manual at 18.
[6] Manual at 23.

The Companies performed the four traditional DSM-EE cost-benefit tests for each of the DSM-EE programs in the Proposed DSM-EE Program Plan. The results of the cost-benefit tests for all of the programs in the Proposed DSM-EE Program Plan are shown below. Note, a score of 1.0 or greater is "passing," meaning that the value of the program's benefits is equal to or greater than the cost of the program:

Program	TRC	PCT	RIM	PAC
Program Development & Administration (PD&A)	0	NA	0	0
Income-Qualified Solutions	0.27	NA	0.13	0.27
Appliance Recycling	1.02	NA	0.20	0.81
Res Online Audit and HVAC/Water Heat	0.74	5.10	0.19	1.06
Business Solutions	1.84	7.40	0.27	7.93
Connected Solutions	3.52	12.65	0.94	1.17
Peak Time Rebates	2.62	NA	0.40	0.40
Nonresidential Demand Response	1.68	1.36	1.34	1.37
Overall Portfolio	**1.54**	**7.53**	**0.32**	**1.83**

Q. Why are the cost-benefit tests set out in the California Standard Practice Manual important?

A. These tests provide an independent assessment of the value of the program to the various entities that are impacted by them individually, such as participants, the utility, and ratepayers, or together for all of the above.

Q. Why are the Companies proposing programs in the DSM-EE portfolio that do not pass the cost-benefit tests?

A. The Companies are proposing some programs that do not pass the cost-benefit tests, but are nevertheless reasonable, for reasons that are not accounted for within cost-effectiveness screening. The Income-Qualified Solutions programs serves a need among the low- and moderate-income population in the Companies' service territories.

Although the Income-Qualified Solutions program (including the WeCare Program) does not pass the California cost-effectiveness tests, it serves some of the Commonwealth's most vulnerable customers. For that very reason, the Companies are proposing to continue and expand upon the WeCare Program; indeed, the Companies are proposing to make their Income-Qualified Solutions one of the most highly funded programs of the Companies' DSM-EE Program Portfolio.

The Residential Online Audit Program consists of both educational and prescriptive rebate components. Although the education aspect alone does not have a measurable benefit to incorporate into the Total Resource Cost Test thus resulting in a value less than 1.0, it is an important aspect of the program to provide guidance to residential customers on their individual energy efficiency improvement opportunities and their overall value they may expect to achieve.

Q. What are the projected overall costs and benefits of the DSM-EE program portfolio the Companies are proposing in this proceeding?

A. The tables below show the annual energy, demand, and gas savings the Companies project the proposed DSM-EE program portfolio will produce:

Energy Efficiency Portfolio:

	Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Energy[1]	MWh	92,446	101,411	130,165	150,229	153,233	132,065	115,034	**874,584**
Demand	MW	18.2	20.0	25.7	29.3	29.4	25.3	22.0	**170.0**
Gas	CCF	149,125	171,196	204,251	260,979	314,589	300,442	299,101	**1,699,683**

[1] Annual energy efficiency savings associated with measures sold through the Online Transactional Marketplace subcomponent of Connected Solutions are also shown in this table.

Demand Response Portfolio:[7]

[7] The demand response portfolio savings would be achieved under peak conditions.

	Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Energy	MWh	288	361	444	554	667	782	782
Demand[1]	MW	154.7	155.7	160.4	174.7	197.3	207.5	206.9
Gas	CCF	0	0	0	0	0	0	0

[1] Annual impacts represent summer demand only.

To achieve these benefits, the Companies project a total DSM-EE portfolio cost of $341 million from 2024 to 2030. The proposed annual budget per program per year is provided in the following table:

Costs ($000s)	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Program Development and Administration	3,628	3,556	2,710	2,889	2,769	2,801	2,983	21,336
Income-Qualified Solutions	10,060	10,072	10,239	10,106	10,123	10,141	10,160	70,902
Appliance Recycling Program	0	0	1,671	1,723	1,926	1,778	1,781	8,880
Residential Online Audit Program	0	1,085	1,265	1,597	1,681	1,636	1,640	8,904
Business Solutions	5,290	5,795	7,820	8,078	8,400	7,502	7,014	49,899
Connected Solutions	5,817	5,922	7,185	11,236	21,955	23,386	25,237	100,739
Peak Time Rebates	250	2,745	2,959	5,682	9,922	10,075	9,929	41,562
Demand Response Program	3,469	4,134	4,650	5,579	6,452	7,329	6,908	38,520
Total Portfolio Budget	**28,514**	**33,309**	**38,499**	**46,890**	**63,228**	**64,649**	**65,653**	**340,742**

Q. How do the Companies ensure that their DSM-EE programs remain effective after they are approved and implemented?

A. The Companies recognize the value in having a continuous improvement process for programming. The Companies currently use a third-party contractor to examine program design, delivery, impacts, and processes. The contractor ensures quality and effectiveness of the programs, optimal use of resources, and responsiveness to customers' needs.

The Companies will use the results and guidance to ensure that all of the programs contained in this filing demonstrate continuous improvement and remain a good application of customer dollars. The Companies typically evaluate their DSM-EE programs in two phases, process evaluation and impact evaluation. Process evaluation is a systematic assessment of an energy efficiency program for the purposes of improving its design, delivery, and perceived quality and usefulness to customers. Impact evaluation focuses on quantifying the energy and demand savings and other economic benefits of the program. The Companies plan to engage in this evaluation a minimum of one time during a 7-year plan period in order to quickly make changes necessary to ensure the continued cost-effectiveness of the Companies' DSM-EE programming.

Q. Have you included with your testimony the supporting calculations for the DSM cost recovery mechanisms?

A. Yes. Attached as Exhibit LI-3 are the supporting calculations for KU's DSM cost recovery mechanism. Exhibits LI-4 and LI-5 provide the supporting calculations for LG&E's electric and gas, respectively, DSM cost recovery mechanisms.

Q. Are you providing the workpapers to support the Proposed DSM-EE Program Plan?

A. Yes. Attached as Exhibit LI-6 are the supporting workpapers for the Proposed DSM-EE Program Plan, which include data the Companies provided to Cadmus to complete the DSM analysis, all of Cadmus's input data, and all outputs from Cadmus. As Mr. Bevington discusses further in his testimony, the Companies provided the same files, with one exception,[8] to members of the DSM-EE Advisory Group that signed a non-disclosure agreement.

[8] In the file titled "LG&E KU Program Measure Inputs FINAL," the Companies aggregated budget information on the "LGE-KU Budgets" tab so that it could be filed publicly. The Companies provided the file to DSM-EE Advisory Group members that signed a non-disclosure agreement in original, non-aggregated form.

CONCLUSION

Q. What is your recommendation for the Commission?

A. I recommend the Commission approve the Companies' application. The Companies are committed to identifying and pursuing cost-effective DSM-EE measures and the Proposed DSM-EE Program Plan will provide significant and necessary demand-side resources.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lana Isaacson**, being duly sworn, deposes and says that she is Manager - Emerging Business Planning and Development for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Lana Isaacson

Lana Isaacson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of December 2022.

Judy Schooler

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

APPENDIX A

Lana Isaacson
Manager, Emerging Business Planning and Development
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4335

Previous Positions

LG&E and KU Services Company	
Manager, Emerging Business Planning & Development	Nov. 2021 – Present
Senior Key Account Manager	Apr. 2019 – Nov. 2021
Schneider Electric	
Director, Client Management	Nov. 2008 – Apr. 2019
Client Manager	Aug. 2001 – Nov. 2008
Austin Utilities	
Director, Customer Service and Key Accounts	Aug. 1999 – Aug. 2001
Interstate Power Company/Alliant Utilities	
Key Account Manager	July 1994 – Aug. 1999

Professional/Trade Memberships

Engineer-in-Training (EIT) License

Education

Professional Development, Leadership Development Program, University of North Carolina Kenan-Flagler Business School, September 2014

Bachelor of Science in Engineering, Mechanical Engineering, The University of Iowa, December 1993

Civic Activities

Active volunteer in various ministries through Southeast Christian Church, including:

- Southeast Christian Church (children's ministry check-in volunteer)
- Habitat for Humanity (building frames for homes)
- Dare to Care (filling backpacks with food for children in need)
- Shine Prom (event for adults with physical or mental disabilities)
- Fuller House (renovating homes for eligible families)
- Prodigal Ministries (prisoner release housing program)
- Life in Abundance (collecting and packaging foods for delivery to people in need)

Exhibit LI-1

2022 Cross-Sector DSM Potential Study Projection

CADMUS

Memorandum

To: John Bevington, Lana Isaacson, John Hayden, and Justin Bencomo; Louisville Gas & Electric and Kentucky Utilities

From: Jeana Swedenburg, Aquila Velonis, and Andrew Grant; Cadmus

Subject: 2022 Cross-Sector DSM Potential Study Projection

Date: November 30, 2022

Louisville Gas and Electric and Kentucky Utilities (the Companies) contracted with Cadmus to conduct a 20-year industrial sector potential assessment in 2016 and a residential and commercial sector potential study in 2017.[1,2] The planning horizon for both potential assessments covers the Demand-Side/Energy Efficiency (DSM/EE) Program Plan filing period (2024-2030).

The current market landscape has shifted fairly dramatically since these two assessments were performed. Legislation and federal codes and standards updates have increased the baseline for many energy efficiency measures that previously represented much of the Companies' market potential. For example, the Energy Independence and Security Act of 2007 has increased the baseline for almost all residential lighting measures, which diminishes the savings for this end-use category.

The Companies commissioned this study in conjunction with their analysis of the 2024-2030 DSM/EE Program Plan. This potential study projection seeks to provide a realistic representation of the current DSM/EE energy and demand savings potential in the Companies' Kentucky territories. This study does not address demand response potential, which was the subject of the 2023 LG&E and KU Demand Response Assessment Cadmus provided to the Companies on April 1, 2021. Compared to the potential identified in the Companies' studies performed in 2016 and 2017, the 2022 potential study projection shows that cumulative electric energy-savings technical potential has declined by approximately 12% over the 20-year study horizon in the five years since the previous studies were completed.

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1 Cadmus. April 2016. *Industrial Sector DSM Potential Assessment for 2016-2035.*

2 Cadmus. March 2017. *Demand Side Management Potential Study 2019-2038*.

Boulder
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Research Approach

This analysis addresses three commonly defined types of DSM market potential:

- ***Technical potential*** represents all technically feasible energy efficiency measures being implemented, regardless of their costs or market barriers.
- ***Economic potential*** represents a subset of technical potential, comprising only measures meeting cost-effectiveness criteria based on the Companies' avoided supply costs for delivering electricity and natural gas and for avoided line losses.
- ***Achievable potential*** represents the portion of economic potential assumed to be reasonably achievable in the course of a planning horizon (typically 20 years), given market barriers that may impede customers' participation in utility programs.[3]

Due to uncertainty created by the introduction of Inflation Reduction Act funding to the DSM landscape, Cadmus developed a methodology to adjust the previous 20-year sector potential assessments using calculations to adjust prior results based on new market data. This methodology follows these steps:

1. Adjust 20-year sales forecast to align with the new horizon (2024-2043)
2. Account for end-use equipment turnover since the original start years of the previous studies
3. Research current and upcoming approved federal standards and compare against federal standards that were current in the previous studies
4. Apply new federal standards impacts to potential annually using efficiency change ratios to adjust end-use equipment potential
5. Using the federal standard research applied to equipment measures, account for equipment annual turnover impacts to discretionary measures
6. Incorporate 2016 to 2021 program accomplishments, provided by the Companies, where possible, to account for already achieved potential
7. Apply market adjustments to specific measure technologies based on how the market has transformed since the previous studies
8. Summarize and conduct quality control (QC) on results against individual changes and compare to previous studies' results

Though Cadmus' analysis to update the previous potential assessments was robust, some limitations should be noted when reviewing the final 2024-2043 potential projections. The projections do not include a complete measure characterization review, so increases in high-efficiency equipment standards, such as changes in ENERGY STAR® specification requirements or the inclusion of new highest efficiency or emerging technologies since the 2016 and 2017 studies were not accounted for in this analysis. In addition, this analysis did not entail a measure or fuel cost update or cost-effectiveness model re-run, so the overall economic potential values reflect the same percentage changes applied to technical potential values (in other words, for this analysis Cadmus treated technical and economic

[3] This analysis does not consider Program potential because the Companies were not considering particular programs in this potential update.

potential adjustments the same). *However, it should be noted equipment cost and labor/installation cost have only increased since these studies due to inflation and other market drivers*.

This task was largely intended to identify the overall impact from new or upcoming federal standards and to capture recent market changes for select measures. The approach and methodology applied in the potential calculations follow similar logic from the 2016 and 2017 potential study models; therefore, the overall results produce realistic projections of the impact from these federal standards and market changes.

Market Landscape Review

To make an accurate account of changes to the market since the 2016 and 2017 studies, Cadmus made two specific updates to model inputs:

- **Equipment Efficiency Shares or Percent Incomplete updates** - The percentage of buildings where customers have not installed the measure, but where its installation is technically feasible, equal to 1.0 minus the measure's current saturation. For example, the Companies' program history (2016-2021) reduces the measure percent incomplete and the availability of new energy efficiency potential.
- **Adjustments to Technical Feasibility constraints** - The percentage of buildings where customers can install this measure, accounting for physical constraints. For example, newer smart thermostats on the market have reduced installation/wiring constraints for customers and increased the availability of adoption.

The equipment shares or percent incomplete updates account for equipment turnover, program accomplishments, and naturally occurring adoption of measures occurring since the previous studies. These types of updates drove down potential due to the shift in the market to more efficient equipment. As noted in the "Implications for DSM/EE Planning" section below, this is consistent with what Cadmus has observed regionally. In addition, these updates for end-use equipment efficiency shares also impact the overall potential for impacted discretionary measures.

Cadmus reviewed adjustments to technical feasibility constraints for specific products based on the current understanding of these measures in specific applications. These technical feasibility constraints increased potential but only for the specific measure rather than the entire end use.

Potential Adjustments

The eight steps in the potential update attempt to accurately adjust potential to reflect the new 20-year horizon (2024-2043) and account for changes to federal standards and for market impacts since the 2016 and 2017 studies.

Step one. Adjust the previous 20-year sales forecast to align with the new 2024-2043 horizon. The previous industrial study had a 2016-2035 horizon, whereas the residential and commercial study had a 2019-2038 horizon. Cadmus calculated an average annual percentage change for the last three years of each study sector by fuel type, building type, vintage, and end-use sales then used these calculations to forecast sales out to 2043.

Step two. Account for end-use equipment turnover since the starting year of the previous studies. This calculation involved taking the previous studies' equipment efficiency shares and calculating the percentage of all systems that have failed and turned over to new systems. To account for the percentage of units that have turned over, Cadmus calculated an annual percentage based on one divided by the estimated useful lifetime assigned to each efficiency level, where equipment that is below the federal standard is assumed to be half the lifetime of a new unit. Cadmus assumed new equipment installations would be at the current federal standard or better efficiency.

To account for the likelihood that the impacted site would install federal standard or better equipment, Cadmus calculated a distribution share based on the historical potential study distribution of federal standard or better equipment. This update impacted the potential for both equipment and discretionary (retrofit) measures.

Step three. Research new or upcoming federal standards against the federal standards present in the previous studies. Though the majority of federal standards already existed in the 2016 and 2017 studies, Cadmus identified and added the following federal standards to the analysis:

- Commercial Refrigeration Equipment – Federal Standard 2017
- Dehumidifiers – Federal Standard 2019
- Pre-rinse Spray Valves – Federal Standard 2019
- Residential Sized Central Air Conditioners – Federal Standard 2023
- Residential Sized Furnaces – Federal Standard 2029
- Residential Sized Heat Pumps – Federal Standard 2023
- Screw Based Lighting – Federal Standard 2022

Step four. To account for new federal standards, adjust annual potential of specific equipment. Cadmus calculated an efficiency equipment adjustment factor to account for changes in federal standards compared to the historical baseline efficiency in the 2016 and 2017 studies. The efficiency equipment adjustment factor was applied to the annual potential of impacted measures. For some measures, this meant that the new federal standard (current for 2022) was the highest efficiency in the 2016 and 2017 studies and, therefore, eliminated all potential for that end use moving forward. An example of that is residential screw base lighting which requires 45 lumens per watt and CFLs are largely no longer available on the market, which forces the baseline to be LEDs. The 2016 and 2017 studies included screw base lighting potential but prior to 2020. As a result, no screw base lighting potential was included in this analysis (2024-2043).

Step five. Apply equipment adjustments (step 4) annually to the discretionary (retrofit) measure potential because changes to end-use equipment consumption directly impact these measures. The impact was on two fronts—one from the change from equipment turnover between the previous potential study start years and this analysis, the other to account for new equipment unit turnover affected by a new federal standard that did not previously exist or did not reflect the year of the previous studies. As a result, as equipment end-use consumption decreases there is less available potential from discretionary/retrofit measures (e.g., weatherization measures).

Step six. Apply program accomplishment impacts to potential estimates for both equipment and discretionary measures. Cadmus used program data based on the number of rebated units and compared these data to the previous studies' estimates of total number of measures. For example, Cadmus compared total rebated commercial horsepower of variable frequency drive (VFD) motors to total regional horsepower of VFD motors. Cadmus developed percentage improvements factors and applied them to the potential projections for these specific measures. Equipment measures, program accomplishments, and discretionary measures of the same end use were also impacted, and their potential was reduced.

Step seven. Review how the market landscape had changed since the previous studies were conducted. In other potential studies undertaken since 2016 and 2017 studies, Cadmus has identified specific technologies to review and benchmark against the input assumptions made in the 2016 and 2017 studies.

For example, Cadmus reviewed residential Wi-Fi thermostat technical feasibility constraints and adjusted the savings upward based on a less restrictive feasibility constraint. Another example of how the market landscape has changed since the 2016 and 2017 studies is LED linear lighting. Though the percentage of LED saturation in the 2016 and 2017 studies were small, the market has largely adopted LED linear lighting technologies. Cadmus projected that not all estimated installations went through the Companies' program, so Cadmus increased the overall saturation of LED linear lighting to align with site visit data collected in other jurisdictions to reflect a more realistic view of the available remaining lighting potential for the Companies.

Step eight. Develop reporting tables and benchmark against historical values to verify that changes made had the expected outcome. Though listed as the final task, Cadmus did this step first so that each subsequent change (steps one through seven) could be verified as implemented and had the expected impact. Overall, the changes had their expected impact on sector and end-use potential, with the overall market potential decreasing due to the impact from federal standards.

Potential Adjustments Results

The final results from the adjustments analysis are shown in Table 1 through Table 3. These tables show technical, economic, and achievable potential, along with the associated baseline sales for the final year and the associated percentage of potential for electric energy, electric demand, and natural gas energy, respectively. The 2043 values represent the adjusted market potential projection, whereas the 2035/2038 values represents the previous potential studies' results (2035 corresponds to the industrial sector and the year 2038 to the residential/commercial sectors). The achievable potential results represent the adjusted achievable scenario[4] results as defined in the previous studies.

More detailed tables of potential results along with annual figures of the medium achievable scenario for electric and natural gas energy can be found in the *Potential Detailed Results - Appendix*.

In Table 1, the technical and economic cumulative electric energy efficiency potential reduced by approximately 12% and 19%, respectively, as a percentage of baseline sales after making the adjustments described above. As noted in the "Implications for DSM/EE Planning" section below, this is consistent with what Cadmus has observed regionally. Lighting and federal standards updates are the predominate drivers for the reduction in potential. The economic cumulative electric energy efficiency potential is reduced by more than the technical potential because the market adjustments impact was greater on the cost-effective measures (e.g., LED lighting).

The achievable potential is a subset of the economic potential and has a similar reduction in potential based on the adjustments.

Across all three categories of potential, the market landscape review saw an increase in potential, but the Companies' program accomplishments and federal standards changes decreased potential. Overall, there was a net reduction in potential relative to the 2016 and 2017 studies, as shown in Table 1. While the market landscape review identified an additional 131 GWh of new cumulative technical electric energy efficiency potential in 2043, there was also a reduction in potential contributed to program accomplishments and federal standards resulting in a net cumulative technical potential of 7,525 GWh. The associated new cumulative economic and achievable electric energy efficiency potential from the market landscape review was 47 GWh and 35 GWh, respectively, with the reduction in potential contributed to the program accomplishments and federal standards resulting in the net cumulative economic and achievable potential of 2,612 GWh and 1,471 GWh, respectively.

Table 1. Cumulative Electric Energy Efficiency Potential – Energy (GWh)

Potential Type	Baseline Sales		Cumulative Potential		Cumulative Potential Percentage of Baseline	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Technical	30,947	30,649	7,525	8,441	24.3%	27.5%
Economic			2,612	3,199	8.4%	10.4%
Achievable			1,471	1,861	4.8%	6.1%

Table 2 shows the cumulative demand reduction potential based on the adjustments and compared to the prior studies. The 2022 adjustments had a smaller impact on the demand reduction potential compared to energy potential relative to the baseline sales.

[4] Cadmus referenced the prior studies "medium" achievable potential scenario that represent customer adoption relative to utility's incentives that cover 50% of the measure incremental cost.

Table 2. Cumulative Electric Energy Efficiency Potential – Demand (MW)

Potential Type	Baseline Sales[1]		Cumulative Potential[2]		Cumulative Potential Percentage of Baseline	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Technical	7,056	6,997	2,020	2,237	28.6%	32.0%
Economic			390	452	5.5%	6.5%
Achievable			221	260	3.1%	3.7%

[1] Cadmus estimated the Companies' demand baseline forecast based on the potential study's end-use hourly profiles and peak demand definitions. This does not represent the Companies' actual demand forecast. These demand potential savings results use the same end-use hourly profiles and peak demand definitions, but do not rely on the estimated demand forecast to determine potential.
[2] These estimates represent cumulative potential (summer peak demand based on the Companies' peak period definitions from the prior studies), not annual or hourly estimates.

In Table 3, the technical and economic cumulative natural gas energy efficiency potential reduced by approximately 12% and 28%, respectively, as a percentage of baseline sales after making adjustments. For natural gas furnace, the pending federal standard in 2029 had an outsized impact on the decline in available potential. The economic cumulative natural gas energy efficiency potential reduces more than the technical potential because natural gas furnaces were cost-effective as well as were other measures associated with the space heating end use.

There was an overall reduction potential (in aggregate) resulting in 10,285,079 MCF of cumulative technical natural gas energy efficiency potential in 2043. However, these measures where not cost-effective and had no impact on the cumulative economic and achievable natural gas energy efficiency potential from the market landscape review.

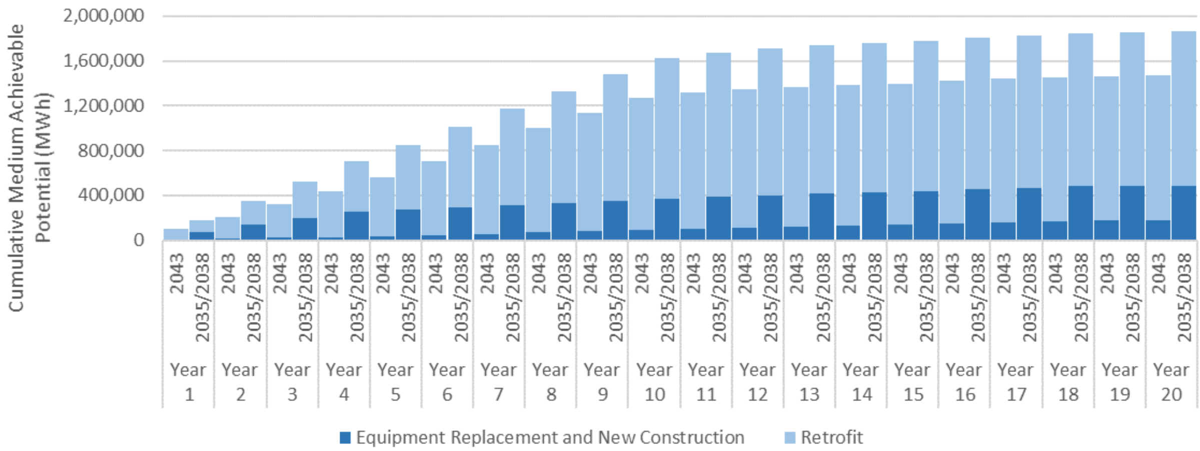
Table 3. Cumulative Natural Gas Energy Efficiency Potential – Energy (MCF)

Potential Type	Baseline Sales		Cumulative Potential		Cumulative Potential Percentage of Baseline	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Technical	27,693,139	28,401,121	10,285,079	11,997,216	37.1%	42.2%
Economic			2,993,976	4,246,480	10.8%	15.0%
Achievable			1,331,762	1,758,783	4.8%	6.2%

Cumulative Achievable Potential – Energy Result Figures

Figure 1 shows the impact from the updates made to the electric energy cumulative medium achievable scenario. The 2043 values represent the adjusted values, and the 2035/2038 values represent the historical values.

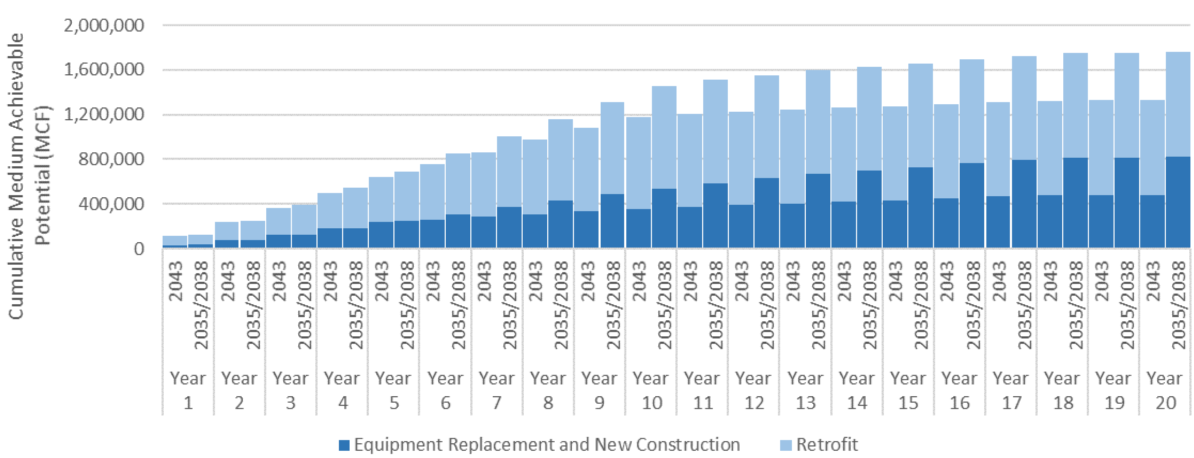
Figure 1. Cumulative Achievable Electric Potential for Medium Achievable Scenario



Though Cadmus made adjustments to account for the shift in timeline and changes in the market, as listed in the *Research Approach* section above, the largest change is the impact from the 2022 federal standard associated to screw base lighting and from the adoption of commercial LED linear and LED fixture lighting applications.

Similar to Figure 1, Figure 2 shows the impact from the updates for natural gas cumulative potential associated with the medium achievable scenario. Though various factors drive differences between the historical potential results and adjusted analysis, the largest delta starts to occur in year 6 for the 2043 adjusted results when the federal standard for residential-sized gas furnaces becomes effective in 2029. This causes a jump in the baseline efficiency requirement from 80% AFUE to 92% AFUE, which has around a 50% reduction for most high-efficiency technologies. In addition, after year 6 the turnover for residential-sized furnace equipment impacts the annual retrofit (discretionary) potential associated with the furnace end use. For example, the potential impact from installing a Wi-Fi thermostat decreases annually after year 6 as the overall market efficiency of residential-sized gas furnaces increases due to the new standard.

Figure 2. Cumulative Achievable Natural Gas Potential for Medium Achievable Scenario



Implications for DSM/EE Planning

The results from this study indicate that available potential is declining and aligns with regional trends. For example, in neighboring Virginia, Dominion Energy's recent energy efficiency potential studies (2014, 2017, and 2020 studies) have shown a steady decline in the available technical and economic potential.[5] These studies showed that technical potential as compared to baseline sales declined from 39% (2014) to 35% (2017) to 32% (2020). The economic potential as compared to baseline sales also showed a decline from 22% (2014) to 19% (2017) to 16% (2020). The Dominion Energy study results of the decline in potential are consistent with Cadmus' study findings.

These observations have several implications for the Companies' DSM/EE planning process. First, DSM/EE planning will need to account for the applicable changes in recent federal equipment standards. This will have an impact on the programmatic unit energy savings that can be claimed for individual measures within the DSM/EE plan, such as heat pumps and air conditioners. Second, low-cost energy efficiency potential is not available (e.g., screw-based lighting), resulting in less remaining potential and potential that is at higher costs to acquire (e.g., may require higher/more incentives to customers). Third, there is a decline in the long-term availability of potential from existing technologies on the market. To minimize this impact, DSM/EE planning may consider larger investments (in incentives and marketing) to acquire savings faster than in prior planning cycles. In addition, DSM/EE planning may need to consider monitoring changes in market and technologies, including emerging technologies, as well as conducting program pilots.

[5] Dominion Energy Efficiency Potential Study: 2020 to 2029 conducted by DNV. Presentation of results "2020-21 Potential Study Results" August 31, 2021, slide 17 "Trends in potential over time".

Potential Detailed Results - Appendix

More detailed results are shown below in the figures and tables below. These tables are broken into three sections:

- Electric Potential – Energy Result Tables
- Electric Potential – Demand Result Tables
- Natural Gas Potential – Energy Result Tables

Electric Potential – Energy Result Tables

Table 4. Technical Electric Energy Efficiency Potential – Energy (GWh)

Sector	Baseline Sales		Cumulative Technical		Cumulative Technical Percentage of Baseline	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Residential	11,605	11,453	3,699	4,143	31.9%	36.2%
Commercial	10,286	10,200	2,503	2,930	24.3%	28.7%
Industrial	9,056	8,997	1,322	1,369	14.6%	15.2%
Total	**30,947**	**30,649**	**7,525**	**8,441**	**24.3%**	**27.5%**

Table 5. Economic Electric Energy Efficiency Potential – Energy (GWh)

Sector	Cumulative Economic		Cumulative Economic Percentage of Baseline		Economic as a % of Technical	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Residential	649	1,093	5.6%	9.5%	17.5%	26.4%
Commercial	779	895	7.6%	8.8%	31.1%	30.5%
Industrial	1,184	1,211	13.1%	13.5%	89.5%	88.5%
Total	**2,612**	**3,199**	**8.4%**	**10.4%**	**34.7%**	**37.9%**

Table 6. Achievable Electric Energy Efficiency Potential – Energy (GWh)

Sector	Cumulative 2043			Cumulative 2035/2038		
	Low	Medium	High	Low	Medium	High
Residential	227	337	381	477	635	710
Commercial	338	542	603	387	620	689
Industrial	391	592	793	400	606	812
Total	**956**	**1,471**	**1,777**	**1,264**	**1,861**	**2,211**

Table 7. Achievable Electric Energy Efficiency Potential as a Percent of Sales – Energy (GWh)

Sector	Cumulative Achievable Percentage of Baseline 2043			Cumulative Achievable Percentage of Baseline 2035/2038		
	Low	Medium	High	Low	Medium	High
Residential	2.0%	2.9%	3.3%	4.2%	5.5%	6.2%
Commercial	3.3%	5.3%	5.9%	3.8%	6.1%	6.8%
Industrial	4.3%	6.5%	8.8%	4.4%	6.7%	9.0%
Total	**3.1%**	**4.8%**	**5.7%**	**4.1%**	**6.1%**	**7.2%**

Electric Potential – Demand Result Tables

Table 8. Technical Electric Energy Efficiency Potential – Demand (MW)

Sector	Baseline Sales[1]		Cumulative Technical[2]		Cumulative Technical Percentage of Baseline	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Residential	3,881	3,843	1,378	1,495	35.5%	38.9%
Commercial	2,082	2,069	480	574	23.0%	27.8%
Industrial	1,092	1,085	162	168	14.8%	15.5%
Total	**7,056**	**6,997**	**2,020**	**2,237**	**28.6%**	**32.0%**

[1] Cadmus estimated the Companies' demand baseline forecast based on the potential study's end-use hourly profiles and peak demand definitions. This does not represent the Companies' actual demand forecast. These demand potential savings results use the same end-use hourly profiles and peak demand definitions, but do not rely on the estimated demand forecast to determine potential.
[2] These estimates represent cumulative potential (summer peak demand based on the Companies' peak period definitions from the prior studies), not annual or hourly estimates.

Table 9. Economic Electric Energy Efficiency Potential – Demand (MW)

Sector	Cumulative Economic		Cumulative Economic Percentage of Baseline		Economic as a % of Technical	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Residential	105	138	2.7%	3.6%	7.6%	9.2%
Commercial	140	166	6.7%	8.0%	29.2%	28.9%
Industrial	145	149	13.3%	13.7%	89.7%	88.6%
Total	**390**	**452**	**5.5%**	**6.5%**	**19.3%**	**20.2%**

Table 10. Achievable Electric Energy Efficiency Potential – Demand (MW)

Sector	Cumulative 2043			Cumulative 2035/2038		
	Low	Medium	High	Low	Medium	High
Residential	36	54	61	51	74	83
Commercial	58	94	105	69	112	125
Industrial	48	73	97	49	74	100
Total	**142**	**221**	**263**	**169**	**260**	**307**

Table 11. Achievable Electric Energy Efficiency Potential as a Percent of Sales – Demand (MW)

Sector	Cumulative Achievable Percentage of Baseline 2043			Cumulative Achievable Percentage of Baseline 2035/2038		
	Low	Medium	High	Low	Medium	High
Residential	0.9%	1.4%	1.6%	1.3%	1.9%	2.2%
Commercial	2.8%	4.5%	5.1%	3.3%	5.4%	6.0%
Industrial	4.4%	6.7%	8.9%	4.5%	6.9%	9.2%
Total	**2.0%**	**3.1%**	**3.7%**	**2.4%**	**3.7%**	**4.4%**

Natural Gas Potential – Energy Result Tables

Table 12. Technical Natural Gas Energy Efficiency Potential - Energy (MCF)

Sector	Baseline Sales		Cumulative Technical		Cumulative Technical Percentage of Baseline	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Residential	17,361,742	17,872,105	7,802,412	8,794,324	44.9%	49.2%
Commercial	8,577,816	8,775,436	2,265,443	2,974,937	26.4%	33.9%
Industrial	1,753,580	1,753,580	217,225	227,955	12.4%	13.0%
Total	**27,693,139**	**28,401,121**	**10,285,079**	**11,997,216**	**37.1%**	**42.2%**

Table 13. Economic Natural Gas Energy Efficiency Potential - Energy (MCF)

Sector	Cumulative Economic		Cumulative Economic Percentage of Baseline		Economic as a % of Technical	
	2043	2035/2038	2043	2035/2038	2043	2035/2038
Residential	2,087,202	3,082,896	12.0%	17.2%	26.8%	35.1%
Commercial	691,609	937,691	8.1%	10.7%	30.5%	31.5%
Industrial	215,166	225,893	12.3%	12.9%	99.1%	99.1%
Total	**2,993,976**	**4,246,480**	**10.8%**	**15.0%**	**29.1%**	**35.4%**

Table 14. Achievable Natural Gas Energy Efficiency Potential - Energy (MCF)

Sector	Cumulative 2043			Cumulative 2035/2038		
	Low	Medium	High	Low	Medium	High
Residential	553,365	872,555	992,570	738,633	1,189,821	1,364,631
Commercial	200,945	351,624	397,331	249,711	456,015	515,945
Industrial	71,005	107,583	144,161	74,545	112,947	151,349
Total	**825,315**	**1,331,762**	**1,534,062**	**1,062,889**	**1,758,783**	**2,031,925**

Table 15. Achievable Natural Gas Energy Efficiency Potential as a Percent of Sales - Energy (MCF)

Sector	Cumulative Achievable Percentage of Baseline 2043			Cumulative Achievable Percentage of Baseline 2035/2038		
	Low	Medium	High	Low	Medium	High
Residential	3.2%	5.0%	5.7%	4.1%	6.7%	7.6%
Commercial	2.3%	4.1%	4.6%	2.8%	5.2%	5.9%
Industrial	4.0%	6.1%	8.2%	4.3%	6.4%	8.6%
Total	**3.0%**	**4.8%**	**5.5%**	**3.7%**	**6.2%**	**7.2%**

Exhibit LI-2

2023 LG&E and KU Demand Response Assessment

CADMUS

Memorandum

To: John Hayden; Louisville Gas and Electric and Kentucky Utilities

From: Lakin Garth, Aquila Velonis, Dylan Harmon, Max Blasdel; Cadmus

Subject: 2023 LG&E and KU Demand Response Assessment

Date: April 1, 2021

Overview

For Louisville Gas and Electric and Kentucky Utilities (LG&E and KU), Cadmus performed the *2016 Industrial Sector DSM Potential Assessment* for 2016 to 2035 and the *2017 Demand-Side Management (DSM) Potential Study* for 2019 to 2038. These studies included estimates of demand response (DR) potential: The *2016 Industrial Sector DSM Potential Assessment* estimated DR potential for eligible industrial LG&E and KU customers only, and *the 2017 Demand-Side Management Potential Study* included DR potential for residential and commercial LG&E and KU customers.

LG&E and KU sought an update to the previously estimated DR potential for all customer sectors. In response to this request, Cadmus updated and combined the previous DR potential assessments for residential, commercial, and industrial LG&E and KU customers, making the following high-level updates:

- Utility information, including recent demand forecasts and customer eligibility requirements
- Program participation assumptions, demand reductions, and cost data for DR products
- Levelized costs and benefit/cost ratios for each DR product
- Estimates of winter DR potential for each sector and DR product
- Timeline for potential DR deployment over a 20-year period, beginning in 2023[1] and ending in 2042

This memo presents the results of an independent assessment of the market potential for electric DR products in the service territory of LG&E and KU over the 20-year planning horizon, from 2023 to 2042. The results of this assessment will help LG&E and KU identify cost-effective DR products and design future programs. In addition, this assessment will identify possible DR products to address LG&E and KU's projected capacity shortfall of 300 to 900 megawatts starting in 2025 through 2028.

This study builds upon previous assessments of DR in LG&E and KU's territory. It incorporates the latest baseline and DR data from primary and secondary sources and is informed by the work of other entities in the region and across the country.

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[1] 2023 aligns with LG&E and KU's planned program update.

Scope of Analysis and Approach

Data Collection

The DR potential study update used LG&E and KU's energy, demand, and customer data. After reviewing all data sources from the two previous potential studies, Cadmus assembled the following data from LG&E and KU: utility sales, forecast, and customer data, residential equipment saturation surveys, and economic assumptions and data including discount rates, line losses, and avoided capacity costs.

Demand Response Product Review

Prior to updating potential estimates, Cadmus compiled a comprehensive list of DR products currently available in the market. Cadmus defined each product and all the relative DR characteristics for each product. These characteristics included applicable sector or segment, controlled end use, approximate product cost, range of unit-level demand reduction, unit-level levelized cost range, DR requirements (e.g., advanced metering infrastructure [AMI] data required), product limitations, market acceptance, and potential competition with other products. Table 1 lists the products Cadmus reviewed.

Based on the findings from the product review, Cadmus, LG&E, and KU screened and selected the most applicable DR products to model DR potential. As noted in Table 1, fourteen products were selected to conduct an in-depth analysis to assess the DR potential.

Table 1. Demand Response Reviewed and Selected Products

Product Class	Product Category	Product	Selected Products	Season	Sector
Direct Load Control (DLC)	Electric Vehicle (EV) DLC	EV Charger Control (Grid-Enabled)		Both	Residential
	Water Heat DLC	Electric Resistance Water Heat – Switch[a]	✓	Both	Residential
		Heat Pump Water Heat – Switch		Both	
		Electric Resistance Water Heat- Grid-Enabled	✓	Both	
		Heat Pump Water Heat - Grid-Enabled		Both	
	Pool Pump DLC	Pool Pump – Switch [a]	✓	Summer	Residential
	Heating and Cooling DLC	HVAC – Switch [a]	✓	Both	Residential or Commercial
		HVAC – Bring-Your-Own-Thermostat (BYOT)	✓	Both	
		HVAC – Direct Install Thermostat		Both	
	Demand Curtailment	AutoDR [a]	✓		Commercial and Industrial
		Manual		Both	
		Backup Generator (Gen) with AutoDR	✓	Both	Commercial and Industrial
	Irrigation DR	Irrigation Pump - Switch		Summer	Agriculture
Price-Based DR	Time of Use (TOU)	Participant-Driven	✓	Both	Residential
	Critical Peak Pricing (CPP)	Smart Thermostat or Participant-Driven	✓	Both	All
	Critical Peak Rebates (CPR)	Smart Thermostat or Participant-Driven	✓	Both	
	Demand Buyback	Bidding Platform		Both	Commercial and Industrial

Product Class	Product Category	Product	Selected Products	Season	Sector
	Interruptible Rates (Int. Rates)	Participant-Driven	✓	Both	
	Real-Time Pricing (RTP)	Participant-Driven	✓	Both	Industrial
Other	Behavioral DR	Real-time Customer Communication	✓	Both	Residential
	Battery Storage DR	Battery Storage - Grid-Enabled		Both	All
	Voltage Reduction	Demand Voltage Reduction (DVR)	✓	Both	All

[a] Programs currently offered by LG&E and KU

Demand Response Potential

For all the DR products selected from the DR product review, Cadmus modeled the DR potential and corresponding costs for the 20-year time frame beginning in 2023 and ending in 2042. As a starting point, Cadmus used existing models from *the 2016 Industrial Sector DSM Potential Assessment* for 2016 to 2035 and the *2017 Demand-Side Management Potential Study* for 2019 to 2038. We updated program participation assumptions, demand reductions, and cost data for each DR product with the recent data from our research and data collection where applicable.

Cadmus estimated both summer and winter DR potential for products that offer demand reduction opportunities in either season, as well as determined levelized costs and benefit/cost ratios for each DR product. We also performed a tipping point analysis for each product to determine the value at which the avoided generation capacity cost meets minimum cost-effectiveness criteria.

Summary of Results

Focusing on reducing a utility's capacity needs, DR programs rely on flexible loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to reduce peak demand and promote improved system reliability and may defer investments in delivery and generation infrastructure.

DR objectives may be met through a broad range of strategies, both price-based (such as time-of-use or interruptible rate) and incentive-based (such as DLC) strategies. This assessment considered 14 total DR product options[2] to estimate total market DR potential in LG&E and KU's service area during peak load. These product options included multiple residential and commercial DLC products targeting cooling, heating, and water heating end uses, commercial and industrial demand curtailment, and others. Cadmus reviewed recent DR literature, including evaluations of pilots and programs across the country, to design each DR program.

[2] Cadmus assess 14 total products with several products having multiple design structures. For example, critical peak pricing products may include 'with enablement' or 'without enablement' (e.g., with and without smart thermostat control). As a result, 14 products totaling 18 product configurations were assessed for DR potential.

Summary of Market Potential

Cadmus ran four utility-season models to generate market potential results for LG&E and KU – one for each utility-season combination. Table 2 and Table 3 in the following sections present the summer and winter market potential for each modeled DR product in LG&E and KU's territory. The tables are specific to one of the product classes (DLC, curtailment, or price-based) and present market potential results for the first six years and the final year of this study. We modeled products that would require a new rate structure (most of the price-based products) to begin in 2024 to account for the additional time needed to submit a new rate case. We modeled all other products to begin in 2023.

Summer Potential

Cadmus modeled LG&E and KU's existing residential and small commercial DLC programs as well as a new BYOT product and a replacement heat pump/air conditioner (HP/AC) switch program.

Cadmus based the existing pool pump and water heating DLC product results on current participation counts and annual attritions—we did not model any new participants for these programs. Furthermore, we set these products to expire in 2028 in the model due to LG&E and KU's intention to pursue other options over these products.

The existing HP/AC DLC products (one-way and two-way)[3] have far more participants than the existing pool pump or water heat products, which is reflected in their much higher market potential. These modeled products are based on the assumption that all one-way and two-way HP/AC switches in LG&E and KU's inventory will be deployed in 2023. The market potential for the existing one-way HP/AC switches then declines 5% a year to reflect annual attrition.

The market potential for the existing two-way HP/AC switches, however, does not decline as quickly as the existing one-way HP/AC switches due to their greater reliability. The new HP/AC product mirrors the decline in existing one-way switches and demonstrates the scenario where LG&E and KU would replace all existing one-way HP/AC switches with two-way switches. This new HP/AC switch product also achieves the maximum market potential modeled—it achieves more market potential at full maturation (in 2042) than LG&E and KU's existing HP/AC DLC program.

Cadmus also modeled a BYOT product. This product targets customers with smart thermostats and pays participants an incentive to curtail load during events, similar to a switch DLC program. Table 2 presents the market potential results for the various DLC products modeled.

3 One-way switch refers to one-way signal communication to activate during an event. Two-way switch provides send and receive signal communication during an event and can validate operation. As of 2020, LG&E and KU has roughly 160,000 one-way HP/AC switches deployed, 15,000 two-way HP/AC switches deployed, and 7,000 two-way HP/AC switches in storage.

Table 2. DLC Products - Summer Market Potential

Product	Summer Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Res DLC BYOT	0.2	0.2	0.9	2.8	5.5	9.2	44.4
Existing HP/AC DLC Program - One Way	62.0	58.8	55.5	52.2	49.0	45.7	0.0
Existing HP/AC DLC Program - Two Way	11.5	10.7	10.0	9.3	8.7	8.1	3.1
New HP/AC DLC Program	0.2	0.9	2.6	6.8	12.8	20.5	88.0
Existing Water Heat (WH) DLC Program	2.0	2.0	2.0	2.0	2.0	0.0	0.0
Existing Pool Pump DLC Program[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[a] The existing pool pump DLC program has very few participants making the market potential for the existing program a near-zero megawatt value.

Cadmus leveraged prior LG&E and KU implementation contract projections of the commercial curtailment program (2014) as well as from current megawatt commitments through the existing program (2020). Additionally, we modeled the curtailment programs with a $15 per kilowatt incentive that align with existing program offering. This incentive is low compared to similar programs across the country and an increased incentive could bring greater megawatt reductions. Similar programs have incentives ranging from $25 per kilowatt to $73 per kilowatt.[4] There is a ceiling to participation regardless of incentive based on customer energy needs limitations.

Cadmus conducted a price elasticity of demand analysis by varying incentives to assess the sensitivity of the potential demand reduction.[5] As the incentive increases from $15 to $30 per kilowatt, there could be an increase of potential by roughly 48%. Increasing the incentives $15 to $45 per kilowatt could see an increase by about 82% in the potential demand reduction.

Cadmus assessed the demand response curtailment potential for the industrial segment, which represents an eligibility expansion to LG&E and KU's existing curtailment program. While this analysis is based on system load shapes and customer segments, the actual ability of a customer to participate in a curtailment program is dependent on their business practices and the ability to interrupt or suspend operations. This is especially difficult to estimate for industrial customers because of the more unique situations of customers considering their industry and operating requirements.

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4 Colorado Springs Utilities. Accessed 3/19/2021. "Peak Savings Program." https://www.csu.org/Pages/PeakSaving.aspx

CPS ENERGY. Accessed 3/19/2021. "Demand Response." https://cpsenergy.com/content/dam/corporate/en/Documents/EnergyEfficiency/DemandResponse.pdf

Eversource. Accessed 3/19/2021. "Demand Response." https://www.eversource.com/content/docs/default-source/save-money-energy/curtailment-demand-response.pdf?sfvrsn=8b3bc962_4

5 The price elasticity value of 0.58 was used for this analysis according to the following: The Energy Journal. 2020. "Utility Customer Supply of Demand Response Capacity" by James Stewart.

The interruptible rates product includes both commercial and industrial customers and so it directly competes with the curtailment programs. It also would require extra steps to develop due to the need for a new rate case which would also need approval.

The modeled backup generator DR product suggested low potential in LG&E and KU's territory. This type of program can be difficult to estimate potential for as reliable data on existing generators is difficult to obtain. Cadmus assumed a portion of health care facilities, airports, and industrial facilities would have backup generation and that a subset would participate in the program. There are additional factors to consider when promoting backup generators, such as the cost of upgrading generators to comply with air quality regulations. Table 3 shows the additional potential for the existing commercial curtailment program and products.

Table 3. Curtailment Products - Summer Market Potential

Product	Summer Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Commercial Curtailment-AutoDR	23.5	25.6	27.6	29.6	31.5	33.4	33.3
Industrial Curtailment-AutoDR	0.0	0.6	2.3	4.6	9.1	13.6	22.4
C&I Curtailment-Backup Generator	0.0	0.2	0.7	1.5	2.2	2.9	7.1
C&I Interruptible Rates	0.0	1.6	6.2	12.4	24.7	36.9	59.5

Residential CPP and CPR are very similar in their effect, but are implemented differently by the utility. The biggest advantage of CPR over CPP for LG&E and KU is that a new rate case is not required. Moreover, CPR encourages load shifting during peak times via incentives, which motivates participation more than the residential behavioral DR product.

All modeled price-based programs require AMI deployment, which we incorporated into the modeling. AMI is used for evaluation, measurement, and verification (EM&V) for the price-based programs by comparing energy consumption during events to baseline averages for similar days. These customer baseline values may change overtime as data improve and vary by season.

The with enablement/no enablement distinction for the CPP/CPR products is related to how peak load shifting is achieved. With enablement products use smart thermostats to instigate a shift in a customer's load (though the customer can override this). No enablement products rely on customer's themselves to curtail their load during called events. While the ease and effectiveness of participation with enablement is greater, the eligibility for these programs is dependent on smart thermostat saturations. This suppresses their market potential in the early years of the programs. It should be noted that enablement could be achieved through other technologies, but smart thermostats are the most common technology used for residential programs.

Cadmus modeled DVR market potential using benchmarked data sources and documents found in LG&E and KU's most recent rate case, including the CVR potential study. It is important to note that CVR and DVR are mutually exclusive. Once CVR/DVR infrastructure is in place, the utility can decide to use it to prioritize peak load reduction or to limit energy consumption. In either case, the observed benefits of this new infrastructure will highly depend on the nature of the customers attached to the controlled substations as CVR and DVR's effectiveness varies by end use. Table 4 includes results for the price-based products, as well as DVR and residential behavioral DR.

Table 4. Pricing/Other Products - Summer Market Potential

Product	Summer Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
DVR	5.5	7.4	9.3	11.2	13.0	13.0	12.8
Industrial RTP	0.0	0.0	0.2	0.6	1.4	2.0	3.4
Residential Behavioral DR	0.0	0.2	0.5	1.1	1.9	2.5	3.3
Residential CPP-No Enablement	0.0	0.2	1.1	2.7	6.3	9.5	16.3
Residential CPP-With Enablement	0.0	0.1	0.4	1.1	3.0	5.1	24.2
Residential CPR-No Enablement	0.2	0.9	2.3	5.4	9.5	12.6	16.3
Residential CPR-With Enablement	0.0	0.2	0.8	2.2	4.5	6.8	24.2
Residential TOU	0.0	0.4	2.7	6.4	11.3	15.0	27.2

Winter potential

Cadmus modeled all DR products for both seasons, except for DLC pool pumps. The results reflect the seasonal shift in energy demand by end use and system shape. Winter potential is higher for most price-based products and industrial curtailment programs. This is primarily driven by a difference in seasonal end use shares.

Table 5 displays the winter results for the modeled DLC products. Compared with the summer results, winter market potential values are lower for each HP/AC DLC product. This is primarily due to the difference in applicable equipment saturations. Nearly all LG&E and KU customers have electric AC units that can be curtailed during summer events, but less than half have electric heating units (air source heat pumps) that can be targeted for winter event curtailment.[6]

Table 5. DLC Products - Winter Market Potential

Product	Winter Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Residential DLC BYOT	0.1	0.1	0.3	0.9	1.7	2.8	13.7
Existing HP/AC DLC Program - One Way	13.4	12.7	11.9	11.2	10.5	9.8	0.0
Existing HP/AC DLC Program - Two Way	3.5	3.2	3.0	2.8	2.6	2.4	0.9
New HP/AC DLC Program	0.1	0.3	0.8	2.2	4.1	6.5	28.1
Existing WH DLC Program	2.0	2.0	2.0	2.0	2.0	0.0	0.0

[6] Based on LG&E and KU's 2020 Heating and Cooling Source Appliance Survey.

Curtailment programs in the winter months saw slightly higher potential for programs that target industrial customers as indicated in Table 6.[7] While commercial potential is slightly less in the winter, it remains comparable to the summer months, making this a dependable year-round product.

Table 6. Curtailment Products - Winter Market Potential

Product	Winter Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Commercial Curtailment-AutoDR	22.1	24.1	26.0	27.9	29.7	31.5	31.4
Industrial Curtailment-AutoDR	0.0	0.7	2.7	5.4	10.7	16.0	26.4
C&I Curtailment-Backup Generator	0.0	0.2	0.9	1.8	2.8	3.6	8.8
C&I Int. Rates	0.0	1.6	6.4	12.8	25.4	38.0	61.3

Table 7 shows that all the price-based products and DVR and residential behavioral DR saw greater potential in the winter months compared with the summer months. This is demonstrative of the winter peak observed LG&E and KU annually.

Table 7. Pricing/Other Products - Winter Market Potential

Product	Winter Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
DVR	6.9	9.2	11.5	13.8	16.1	16.1	16.0
Industrial RTP	0.0	0.1	0.3	0.7	1.6	2.4	4.0
Residential Behavioral DR	0.1	0.3	0.7	1.8	3.1	4.1	5.3
Residential CPP-No Enablement	0.0	0.3	1.5	3.6	8.4	12.5	21.3
Residential CPP-With Enablement	0.0	0.1	0.5	1.4	3.9	6.6	30.8
Residential CPR-No Enablement	0.2	1.2	3.0	7.2	12.5	16.7	21.3
Residential CPR-With Enablement	0.0	0.3	1.0	2.9	5.8	8.8	30.8
Residential TOU	0.0	0.6	4.4	10.5	18.4	24.5	43.9

Summary of Program Costs

Table 8 and Table 9 summarize the modeled program costs by year for each DR product and each season. To assess cost-effectiveness of each season separately, we duplicated all program costs for each season.

Table 8. Summer Program Costs by Year

Product	Summer Program Costs (thousand $)						
	2023	2024	2025	2026	2027	2028	2042
DVR	$371	$104	$112	$121	$129	$65	$64
Industrial RTP	$300	$151	$152	$154	$159	$158	$150
Residential Behavioral DR	$152	$12	$30	$72	$126	$169	$218
Residential DLC BYOT	$168	$25	$96	$285	$565	$938	$4,537

[7] It is important to note that these results are for both utilities combined and the unique distribution of customer types, system shape, and other factors specific to each utility would affect the potential for each utility.

Product	Summer Program Costs (thousand $)						
	2023	2024	2025	2026	2027	2028	2042
Existing HP/AC DLC Program - One Way	$4,732	$4,483	$4,234	$3,985	$3,736	$3,487	$0
Existing HP/AC DLC Program - Two Way	$651	$608	$567	$529	$494	$461	$177
New HP/AC DLC Program	$82	$273	$747	$1,893	$2,879	$4,010	$7,973
Existing WH DLC Program	$368	$367	$365	$364	$362	$0	$0
Existing Pool Pump DLC Program	$1	$1	$1	$1	$1	$0	$0
Residential CPP-No Enablement	$300	$178	$265	$357	$623	$588	$255
Residential CPP-With Enablement	$300	$154	$170	$195	$270	$290	$289
Residential CPR-No Enablement	$321	$247	$335	$583	$730	$652	$313
Residential CPR-With Enablement	$302	$165	$189	$257	$331	$359	$471
Residential TOU	$150	$66	$410	$675	$877	$706	$110
Commercial Curtailment-AutoDR	$730	$847	$884	$920	$956	$992	$944
Industrial Curtailment-AutoDR	$346	$244	$355	$453	$709	$843	$859
C&I Curtailment-Backup Generator	$347	$532	$1,212	$1,581	$1,630	$1,680	$780
C&I Int. Rates	$346	$244	$355	$453	$709	$843	$859

Table 9. Winter Program Costs by Year

Product	Winter Program Costs (thousand $)						
	2023	2024	2025	2026	2027	2028	2042
DVR	$424	$129	$139	$150	$161	$80	$80
Industrial RTP	$300	$151	$152	$154	$159	$158	$150
Residential Behavioral DR	$154	$20	$49	$118	$206	$275	$352
Residential DLC BYOT	$154	$6	$24	$70	$140	$232	$1,122
Existing HP/AC DLC Program - One Way	$1,107	$1,049	$991	$932	$874	$816	$0
Existing HP/AC DLC Program - Two Way	$152	$142	$133	$124	$116	$108	$41
New HP/AC DLC Program	$20	$68	$186	$471	$717	$998	$1,986
Existing WH DLC Program	$368	$367	$365	$364	$362	$0	$0
Residential CPP-No Enablement	$300	$178	$265	$357	$623	$588	$255
Residential CPP-With Enablement	$300	$154	$170	$195	$270	$290	$289
Residential CPR-No Enablement	$321	$251	$345	$607	$772	$709	$384
Residential CPR-With Enablement	$303	$168	$197	$282	$381	$435	$732
Residential TOU	$150	$66	$410	$675	$877	$706	$110
Commercial Curtailment-AutoDR	$770	$917	$958	$997	$1,038	$1,077	$1,012
Industrial Curtailment-AutoDR	$346	$245	$359	$462	$727	$870	$903
C&I Curtailment-Backup Generator	$347	$532	$1,212	$1,581	$1,630	$1,680	$780
C&I Int. Rates	$346	$245	$359	$462	$727	$870	$903

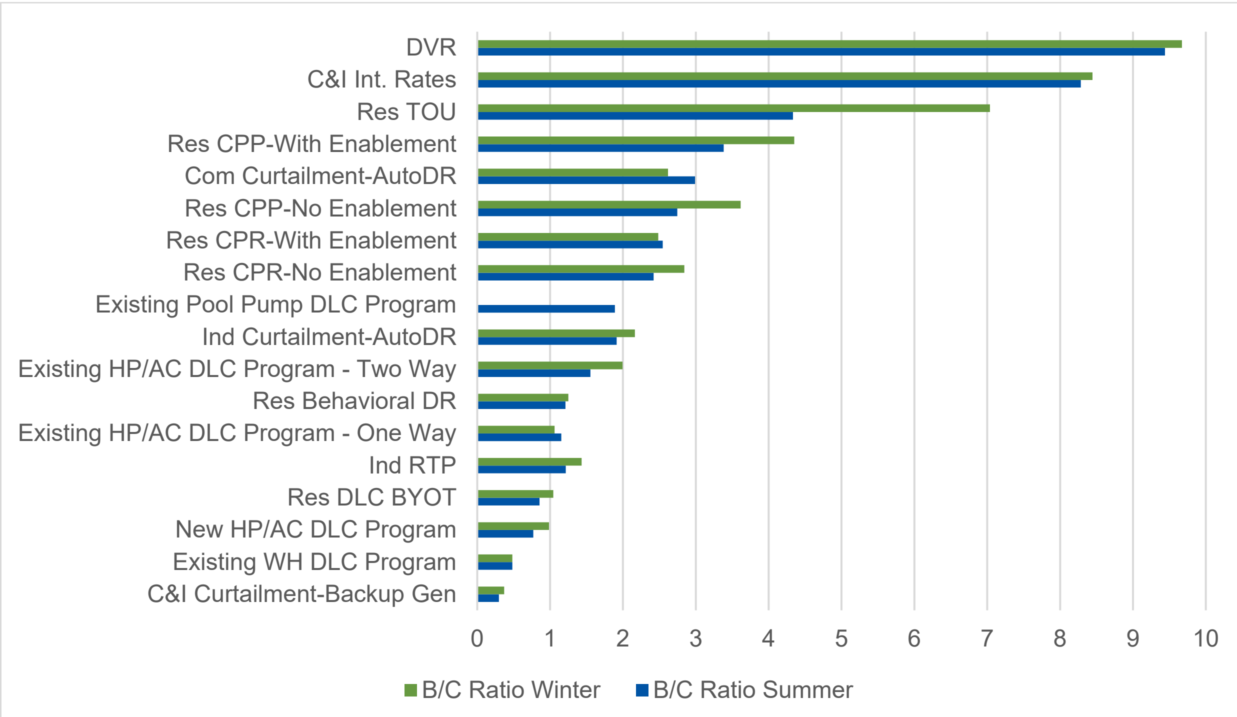
Cost-Effectiveness Results

Cadmus generated benefit/cost ratios for all modeled DR products to compare the cost-effectiveness of each product.[8] Costs include various program costs such as setup costs, marketing costs, equipment costs, O&M costs, incentive payments, and others. The benefits are defined as the avoided capacity cost

8 The benefit/cost ratios following the Total Resource Cost (TRC) test methodology to assess product cost effectiveness. This follows a same approach as prior LG&E and KU demand response program cost effectiveness analysis as part of program planning.

and vary depending on the DR product start year and year of capacity need, identified as 2028. Cadmus used avoided capacity cost estimates provided by LG&E and KU for these calculations.[9] Figure 1 summarizes the benefit/cost ratio of each modeled DR product. All benefit/cost ratios above 1.0 are considered cost effective.

Figure 1. Cost-Effectiveness Results



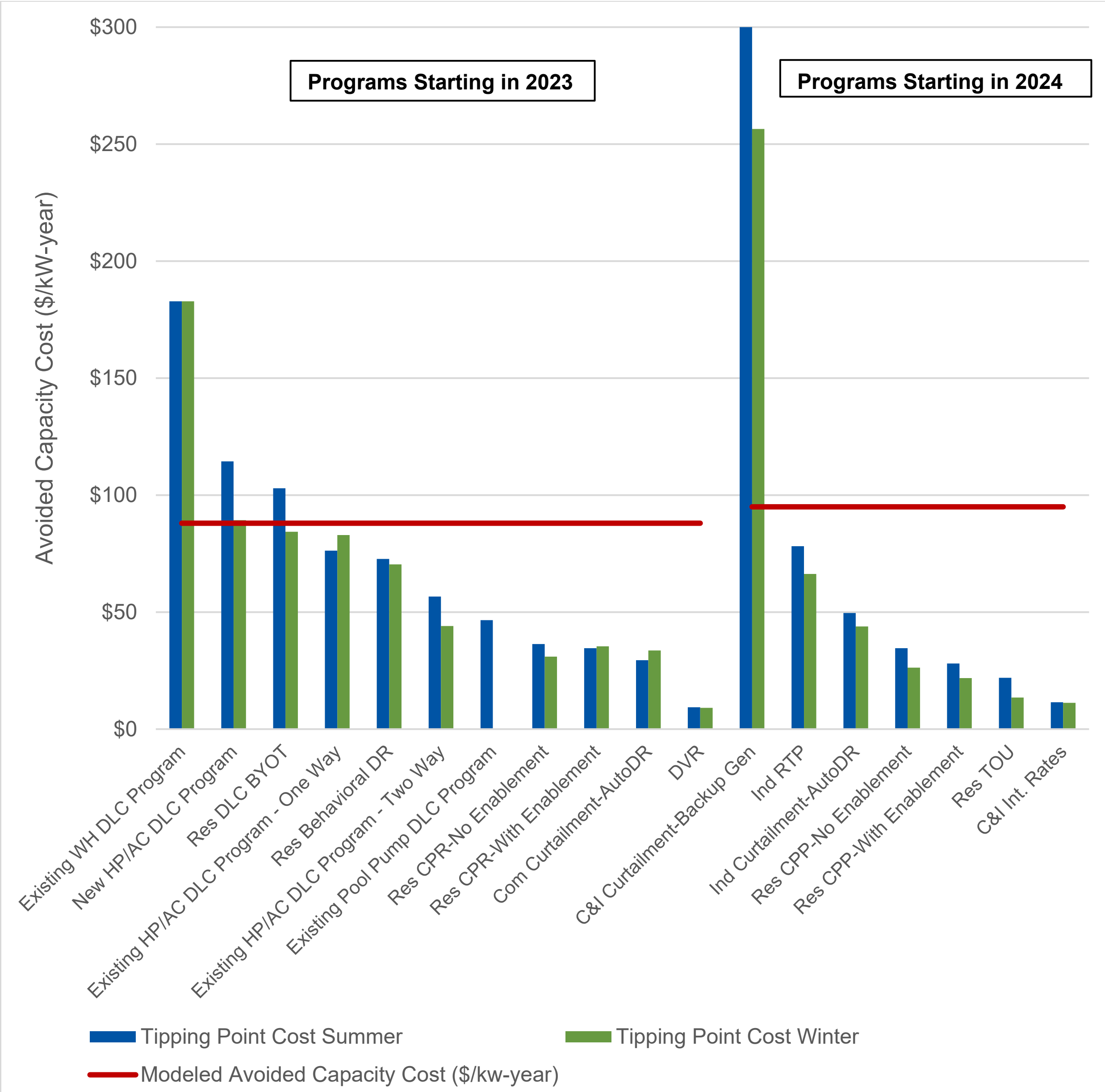
Tipping Point Analysis Results

Cadmus also performed a tipping point analysis for each of the modeled DR products. This analysis determined the minimum threshold the avoided capacity cost (in $/kW-year) needs to be for each DR product to be cost-effective. Because the only benefit considered in this analysis is the avoided capacity cost, these tipping point costs are equivalent to the levelized cost for each product.

As previously mentioned, the avoided capacity cost varies by product start year. We assigned products that begin in 2023 an avoided capacity cost of $88 per kilowatt-year and those that began in 2024 an avoided capacity cost of $95 per kilowatt-year. Figure 2 summarizes the findings of the tipping point analysis. All products lower than avoided capacity cost threshold (red line), the product would still be cost effective with a lower avoided capacity cost. However, all products higher than red line would require higher avoided capacity cost to remain cost effective.

9 LG&E and KU provided Cadmus with a draft document with estimated avoided capacity costs based on the year of capacity need and the year a newly dispatchable program is available.

Figure 2. Tipping Point Analysis Results



Recommendations

There are several key recommendations for LG&E and KU to consider based on the results of this analysis:

- ***Maintain Existing Residential and Small Commercial DLC Switch Program.*** Replacing all existing one-way switches with new two-way switches is not cost-effective. Existing one-way switches will continue to fail, customers will opt-out, etc. By 2028, existing DLC may decline from 66 MW (in 2017) to roughly 54 MW or less (depending on rate of failures and opt-outs). Cadmus recommends partial one-way replacement by expanding the number of two-switches from 22,000 to roughly 60,000 to slow the rate of attrition.
- ***Expand Existing Commercial Curtailment Program.*** The Curtailment program is highly cost-effective and has room to grow. Cadmus recommends expanding commercial customer base (actively recruit new commercial customers) and including industrial customers as eligible participants. Consider increasing incentives to promote the program—this would increase megawatt potential.
- ***Implement New Residential Critical Peak Rebates Program.*** CPR (unlike CPP) does not require a new rate structure and can be deployed quickly. CPR provides more megawatts than residential behavioral DR programs because CPR offers an incentive to participants. Because CPR with enablement requires smart thermostats, Cadmus recommends CPR without enablement to be implemented as it offers more flexibility and faster adoption. It is important to note, this product is reliant upon AMI deployment.
- ***Consider Residential Time of Use.*** This product offers high summer and winter megawatt potential. While it does compete with CPR, it would provide a companion program that gives customers different options. It is important to note, this product is reliant upon AMI deployment and would require a new rate structure.
- ***Evaluate Conservation Voltage Reduction for Demand Reduction.*** Potential for demand reduction as part of CVR is approximately 13 MW (summer) by 2027 if leveraged for demand reduction. Though the actual MW potential is highly dependent on substation customer base. LG&E and KU should either evaluate demand reduction potential from CVR or assess the feasibility of DVR instead of CVR to isolate substations (or control points) with a favorable mix of customer loads for higher demand potential.

Conclusions

LG&E and KU are anticipating a 300 MW to 900 MW capacity shortfall starting as early as 2025 through 2028. To address this shortfall, demand response can provide both short-term and long-term needs as a flexible load reduction resource. Existing LG&E and KU residential and small commercial DLC program have provided 66 megawatts (according to event data in 2017) and the large commercial curtailment program can provide 22 megawatts (according to 2020 customer commitments) of load reduction.

- Compared to LG&E and KU existing programs, the DR products recommended above meet approximately, an additional 21 MW by 2025 and 39 MW by 2028 could be added as a resource through these DR programs for summer peak. As shown in Table 10, in 2025, the total across all recommended products has a summer demand reduction of 109 megawatts. In 2028, the total summer demand reduction is 126.5 megawatts. Cadmus estimated the total levelized costs to be $48.6 per kilowatt-year for the summer peak.

Table 10. Total Demand Reduction of Recommended Products

Product	Summer MW (2025)	Winter MW (2025)	Summer MW (2028)	Winter MW (2028)	Summer Levelized Cost ($/kW-Year)	Winter Levelized Cost ($/kW-Year)
Existing DLC Program	67.5	17.0	53.9	12.3	74.9	82.0
Com Curtailment-AutoDR	27.6	26.0	33.4	31.5	29.4	33.6
Ind Curtailment-AutoDR	2.3	2.7	13.6	16.0	49.6	43.9
Res CPR-No Enablement	2.3	3.0	12.6	16.7	36.4	31.0
DVR	9.3	11.5	13.0	16.1	9.3	9.1
Total	**109.0**	**60.2**	**126.5**	**92.6**	**48.6**	**37.4**

- Commercial curtailment's low levelized cost (tipping point cost) relative to the projected avoided capacity cost suggests additional market, incentives, and program funds could be leveraged to promote and expand this existing program.
  - Cadmus estimated, through a price elasticity of demand analysis, that increasing incentives from $15 to $30 per kilowatt, there could be an increase potential by roughly 48%. This translates to an additional 14.4 megawatts in 2025 and 22.6 megawatts in 2028 or combine across all recommended products totaling 123.4 megawatts and 149.1 megawatts, respectively.
  - Increasing incentives from $15 to $45 per kilowatt could see an increase by about 82% in demand reduction potential. This results in an additional 24.5 megawatts in 2025 and 38.5 megawatts in 2028 or combine across all recommended products totaling 133.5 megawatts and 165.0 megawatts, respectively.
- While the current commercial curtailment program is voluntary (customers can op-out during events), there are program design strategies to make this resource less flexible and more of a firm resource. The following represent a few possible strategies.
  - Set the program target of customer commitments higher than firm resource need.
  - Set customer fee penalties or remove customers who repeatably fail to meet their commitments. However, setting significant penalties may also have adverse effect on program participation.
  - Continue to educate customers about the benefits of demand response and actively promote event participation (LG&E and KU already does this within the current program).

To support LG&E and KU generation planning, Cadmus summarized the demand side management (DSM) megawatt reduction estimate achieved through demand response programs and products. In Table 11, the recommended products (DLC, curtailment, CPR, and DVR/CVR) provide the incremental megawatts (in addition to the demand reduction from existing programs). Cadmus applied a ten percent risk factor to avoid overestimating savings of program achievements and other unforeseen barriers (e.g., customer acceptance). The incremental megawatts from DR could provide generation planning, as a demand response resource, 32 megawatts in 2025 (summer) and 55 megawatts in 2028 (summer). In the event LG&E and KU's pending rate case does not receive approval for AMI deployment, this will limit the number of DR products that can be offered. As result, the non-AMI required DLC and curtailment AutoDR products could provide generation planning 21 megawatts in 2025 (summer) and 32 megawatts in 2028 (summer). The total levelized cost value for planning is $48.6 per kilowatt-year (2023 dollars)[10] for both summer and winter (conservative estimate for both seasons).

Table 11. Demand Response Potential Estimate

Demand Response Potential	Summer MW (2025)	Summer MW (2028)
Total Recommended Existing and New Programs (MW)	109.0	126.5
Incremental MW (Net existing programs ~ 88MW)	21.0	38.5
Additional MW with Higher AutoDR Incentives	14.4	22.6
Total Incremental MW	**35.4**	**61.1**
Program Risk Factor	10%	10%
Incremental MW DSM DR Estimate with AMI for Generation Planning (Rounded)	**32.0**	**55.0**
Incremental MW without AMI Generation Planning (Rounded)	**21.0**	**32.0**

Memorandum Addendum

Upon completion of this project, LG&E and KU became aware the residential and small commercial DLC two-way cellular devices installed with 3G service will no longer be maintained by the communication service provider as of December 31st, 2022. This effectively removes 21,000 two-way switches from the DLC program as well as removes 10.0 megawatts (2025) and 8.1 megawatts (2028) from the analysis conducted within this study. Cadmus suggests two options to mitigate the reduction in potential. First, consider replacing the obsolete equipment with new compatible communication devices. To ensure near-term viability of the DLC program, ongoing maintenance will be required to avoid more loses in demand response potential. Second, consider offering the commercial and industrial curtailment program options high incentives (e.g., $45 per kW) to increase program participation. As indicated within this study, increasing incentives from $30 per kW to $45 per kW could increase potential by 10.1 megawatts (2025) and 15.9 megawatts (2028), thereby offsetting the DLC program losses. In any planning estimate, there remains uncertainty in customer's awareness and willingness to participate in demand response programs that may impact the demand response achieved.

[10] Timeline for potential DR deployment over a 20-year period, beginning in 2023.

Appendix A. Overview of Technical and Market Potential

Cadmus' analysis focused on programs aimed at reducing LG&E and KU's winter and summer peak demands. These programs include DLC space heat & cooling, DLC water heat, DLC pool pumps, nonresidential load curtailment, nonresidential backup generation, residential TOU, CPP, and CPR pricing, nonresidential interruptible rates, nonresidential RTP, and DVR. For these products, Cadmus provided options for all major customer segments and end uses in LG&E and KU's service territory.

We defined each DR program and its associated product option(s) according to typical program offerings, with specifications such as program implementation methods, applicable segments, affected end uses, load-reduction strategies, and incentives. To design the programs, we conducted an extensive review of secondary sources that addressed existing and planned programs throughout the country, such as DR potential assessments, program descriptions, evaluation reports, and pilot and demonstration projects from other utilities.

Estimate Technical Potential

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of DR product, this study applies either a bottom-up or a top-down method to estimate technical potential.

This study uses the bottom-up method for assessing potential for DR programs that affect a piece of equipment in a specific end use, such as residential DLC space heat, residential DLC space cooling, and residential DLC water heat. In the bottom-up method, we determined technical potential as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kilowatt) peak load impact.

The top-down method estimates technical potential as a fraction of the participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use then estimates technical potential as a fraction of the end-use loads. We then estimated total potential by aggregating the estimated load reductions of the applicable end uses. We applied the top-down estimation method to DR products that target the entire facility or load (rather than specific equipment), such as commercial and industrial demand curtailment.

Estimate Market Potential

Market potential reflects a subset of technically feasible DR opportunities we assumed to be reasonably obtainable, based on market conditions and the end-use customers' ability and willingness to participate in the DR market. There are two components for estimating market potential: market acceptance (or the participation rate) and the ramp rate. We also broke down the participation rate into program participation (the likelihood of the eligible population to enroll in a DR program) and event participation (the probability that customers participating in a program will respond to a DR event), an important consideration in voluntary DR programs.

Ramp rates reflect the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of DR product and the stage in the product's life cycle. We included LG&E and KU's projected AMI deployment in the ramp rate calculation for price-based measures that require AMI for EM&V. Ramp rates indicate when the maximum market potential may be reached, but they do not affect the amount of maximum market potential.

Both top-down and bottom-up methods calculate market potential as the product of peak load impact, program participation, and event participation. Both methods apply ramp rates in the same manner to account for program start-up and ramp-up.

Calculate Levelized Costs

In the context of demand response, levelized cost of electricity (LCOE) represents the constant per-kilowatt-year cost of deploying and operating a DR product, calculated as follows:

LCOE = (Annualized Cost of Demand Response Product) / (Achievable Annual Kilowatt Load Reduction)

For this assessment, Cadmus calculated levelized costs based on the total resource cost (TRC) perspective, which includes all known and quantifiable costs related to DR products and programs. The calculation of each DR product's levelized cost accounts for the relevant, direct costs of a DR product, including setup costs, program operation and maintenance costs, equipment cost, marketing cost, incentives, and transmission and distribution (T&D) deferral costs:

- **Upfront setup cost.** This cost item includes LG&E and KU's program development and setup costs for delivery of the subject DR products, prior to program implementation. We split these costs between the two utilities. Because upfront costs tend to be small relative to total program expenditures, they can be expected to have a small effect on levelized costs.
- **Program operations and maintenance (O&M) cost.** This cost item includes all expenses that LG&E and KU incurs annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and new recruiting of loads, and evaluation.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable DR technology for each participating end user. The cost item applies only to each year's new participants. For some programs that assume or require end users to already have DR technology in place, this cost item would be zero.
- **Marketing cost.** This cost item includes all expenses for recruiting end users' participation in the program and applies only to new participants each year. For some programs (typically those run by third-party aggregators), the program O&M cost already includes this cost item.
- **Incremental Cost.** This cost item covers 75% of the incentives offered to end users each year. Incentives may take the form of fixed monthly or seasonal bill credits or may be variable, tied to actual kilowatt load reduction. This assessment included 75% of the assumed incentive payment to eligible participants in the TRC levelized-cost calculation. This approach follows the protocols established by the California Public Utilities Commission for assessing the cost effectiveness of

demand response products. Value for demand response is measured differently than energy efficiency programs for cost effectiveness tests.[2]

- **T&D costs.** Cadmus did not use a T&D value in the levelized cost calculations for each product.
- **Discount rate.** Cadmus used a 6.8% discount rate, consistent with LG&E and KU's resource planning assumptions, for all DR products.
- **Product life cycle.** We assessed all DR products with an assumed 20-year life cycle.[11]
- **Line Loss.** We used line loss values of 5.8% and 6.2% for LG&E and KU, respectively, to calculate demand savings at generation and affect total product benefits.

[11] California Public Utilities Commission 2016 Demand Response Cost-Effectiveness Protocols.

Appendix B. Product Input Assumptions

The tables below summarize the modeling input assumptions Cadmus used for each DR product to generate the potential demand reduction results discussed in the main body of this memo.

Table B-1. Demand Voltage Reduction Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 full-time employee (FTE; split between utilities).
O&M Cost	$ per kW pledged per year	$5	Based on the Northwest Power and Conservation Council's 2021 Plan Bonneville Power Administration (BPA) Workbooks.
Equipment Cost	$ per new kW pledged	$35	
Marketing Cost	$ per new kW pledged	$0	
Incentives (annual)	$ per kW pledged per year	$0	
Incentives (one time)	$ per new kW pledged	$0	
Attrition	% of existing participants per year	0%	
Eligibility	% of segment/end-use load	Industrial: 15% Residential and Commercial: 85%	
Peak Load Impact	% of eligible segment/end-use load	0.47%	Based on LG&E and KU rate case Exhibit LEB-3. Appendix D, Page 2 of 10. Conservative scenario CVR system load reduction estimates a 0.47% load reduction.
Program Participation	% of eligible segment/end-use load	100%	Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks.
Event Participation	%	97%	
Ramp Rate	Number of years to reach maximum achievable potential	5	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-2. Commercial Curtailment AutoDR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per year	$338,000	Based on the LG&E and KU Services Company Contract 2014 (split between utilities) and the Portfolio Performance Fee from the current contract 143095.
Equipment Cost	$ per new participant	$3,250	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Enablement Fee.

Parameters	Units	Values	Notes
Marketing Cost	$ per participant per year	$940	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Management Fee.
Incentives (annual)	$ per kW pledged per year	$15	Based on LG&E and KU website: https://lge-ku.com/business/demand-conservation-large
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of end-use load	KU: 51.7%; LGE: 59.0%	Based on non-residential customer billing database provided by LG&E and KU. Cadmus included only customers with an average annual demand greater than 200 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible segment/end-use load	30%	Based on Colorado Springs (Cadmus 2016): 30%; Black Hills Energy (Applied 2018): 27% from the Black Hills/Colorado 2018 Electric DSM Baseline and Potential Study.
Program Participation	% of eligible end-use load	KU: 11.3%; LGE: 12.6%	Based on customer load of current LG&E and KU curtailment program as a percentage of eligible load.
Event Participation	%	95%	Based on conversation with Enel X representative citing average observed event participation.
Ramp Rate	Number of years to reach maximum achievable potential	7	Based on current program impact and past contracted maximum curtailment MW values.

Table B-3. Industrial Curtailment AutoDR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$196,000	Large Commercial DLC amendment to contract 143095 DR Service & Subscription Fee (split between utilities).
Equipment Cost	$ per new participant	$3,250	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Enablement Fee.
Marketing Cost	$ per participant per year	$940	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Management Fee.
Incentives (annual)	$ per kW pledged per year	$15	Based on LG&E and KU website: https://lge-ku.com/business/demand-conservation-large
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.

Parameters	Units	Values	Notes
Eligibility	% of end-use load	KU: 92.6%; LGE: 88.4%;	Based on non-residential customer billing database provided by LG&E and KU. Cadmus vetted customers with an average annual demand greater than 200 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible end-use load	30%	Colorado Springs (Cadmus 2016): 30%; Black Hills Energy (Applied 2018): 27% from the Black Hills/Colorado 2018 Electric DSM Baseline and Potential Study
Program Participation	% of eligible end-use load	KU: 8.3%; LGE: 9.2%	Determined using current program participants compared to all commercial customers.
Event Participation	% (switch success rate)	95%	Based on conversation with Enel X representative citing average observed event participation.
Ramp Rate	Number of years to reach maximum achievable potential	8	Based on LG&E and KU planning files.

Table B-4. C&I Curtailment Backup Generator Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$196,000	Large Commercial DLC amendment to contract 143095 DR Service & Subscription Fee (split between utilities).
Equipment Cost	$ per new participant	$3,250	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Enablement Fee.
Marketing Cost	$ per new participant	$940	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Management Fee.
Incentives (annual)	$ per participant per year	$5	Enel X Large Commercial DLC Amendment to contract 143095 Portfolio Performance Fee.
Incentives (one time)	$ per year	$800	Additional O&M incentive based on LBNL study of generator costs.
Attrition	% of existing participants per year	5%	Assume same as curtailment.
Eligibility	% of end-use load	Varies by Segment	Based on customer load database provided by LG&E and KU. Cadmus vetted customers with an average annual demand greater than 250 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible end-use load	KU: 17.1%; LGE: 2%	Calculated as 1/4 of peak qualifying customers.
Program Participation	% of eligible end-use load	KU: 3.3%; LGE: 3.6%	Considers likelihood to have generator based on segment and sector.
Event Participation	% (switch success rate)	95%	Based on PGE backup generator program.

Parameters	Units	Values	Notes
Ramp Rate	Number of years to reach maximum achievable potential	12	Assume slower ramp than AutoDR as customers may need to upgrade generators.

Table B-5. C&I Interruptible Rates Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$250,000	Based on the average value from Interstate Power and Light Company 2019-2023 Energy Efficiency Plan (Docket No. EEP-2018-0003)
Equipment Cost	$ per new participant	$0	No equipment costs required to participate.
Marketing Cost	$ per new participant	$25	Assumed based other similar programs.
Incentives (annual)	$ per kW pledged per year	$5.37[a]	Value from Interstate Power and Light Company 2019-2023 Energy Efficiency Plan (Docket No. EEP-2018-0003)[a]
Incentives (one time)	n/a	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assume same as curtailment.
Eligibility	% of segment load	KU: 81.3%; LGE: 85.1%;	Based on customer load database provided by LG&E and KU. Cadmus vetted customers with a maximum demand greater than 250 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible segment load	30%	Colorado Springs (Cadmus 2016): 30%; BHE (Applied 2018): 27% from the Black Hills/Colorado 2018 Electric DSM Baseline and Potential Study
Program Participation	% of eligible segment load	KU: 8.3%; LGE: 9.2%;	Same value as AutoDR.
Event Participation	n/a	99%	Assumed based on high penalties for non-participation.
Ramp Rate	Number of years to reach maximum achievable potential	8	Standard new product ramp up.

[a] Interstate Power and Light requires customers to commit to a minimum 200 kW reduction and achieve the contracted kilowatt reduction amount qualify for an interruptible credit. If customers fail to respond to an event, a one-time financial penalty of $36.50 per kilowatt for each excess kilowatt over their firm contract demand is levied.

Table B-6. Industrial RTP Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$0	Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks.
Equipment Cost	$ per new participant	$200	
Marketing Cost	$ per new participant	$0	
Incentives (annual)	n/a	$0	
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	0%	
Eligibility	% of segment load	100%	AMI dependency captured in ramp rate - eligibility value set to 100%.
Peak Load Impact	% of eligible segment load	Summer: 8% Winter: 4%	Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks.
Program Participation	% of eligible segment load	4%	
Event Participation	n/a	100%	
Ramp Rate	Number of years to reach maximum achievable potential	8	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350, standard product roll out ramp rate, and additional time to establish a new rate class.

Table B-7. Residential DLC BYOT Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per participant per year	$34	Based on a similar western utility pilot Wi-Fi program's costs, and consistent with Energy Hub estimates for software, licensing and DMRS setup of $25 - $35. And marketing based on research ranging from $10-$94 per new customer depending upon program: Consolidate Edison Cool NY pilot $10 and DLC Thermostats 3% total program costs; TVA 2011 potential study $50.
Equipment Cost	$ per new participant	$0	BYOT requires participants already have a smart thermostat.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.

Parameters	Units	Values	Notes
Incentives (annual)	$ per participant per year	$20	Benchmarked thermostat incentives include: PG&E $25; Xcel CO $50 towards purchase $5 per event participated; Austin Energy BYOD $85; Con Ed $25. Incentives for DLC switches include: PSE's pilot $50 for (space heat and water heat); Consolidate Edison Room A/C $10; Consolidated Edison ResSmart $25; Entergy $25 yearly for 50% cycle / $40 and $40 for 100% cycle; TVA potential study $55; ESource benchmarking monthly bill credits range from $5 to $32. Consolidated Edison BYOT incentive for $85 enrollment + $25 additional rebate (ESource); Orange & Rockland BYOT incentive for $85 enrollment + $25 for participation the following summer (ESource).
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Research shows a range from 2% to 9%. MRES 1%; Western Utility 1.5% (2015 Cadmus CPA); Rocky Mountain Power (2010) 2%; IPL's 2014-18 plan assumes 3% attrition; Con Edison evaluation 3.8% (2012); Avista thermostat pilot 4%; BPA Kootenai 5% (pilot), Xcel CO thermostat pilot 9% (2013).
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 95% Winter: 23%	Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Summer eligibility based on percent of questionnaire respondents who reported having an air conditioner in their home. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.
Peak Load Impact	kW per participant (at meter)	Summer: 0.6 Winter: 0.75	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Program Participation	% of eligible customers	20%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%.
Event Participation	% (switch success rate)	75%	CSU pilot in 2005 shows that 8.5% opt out at least 1 hour (Rocky Mountain Institute report); NV Energy 10% -13% non-responsive devices (NRD) including opt-out; CA Statewide report (1990s) 20% NRD during peak; Excel Co 54% of tech impact when including opt-out and off-line equipment (Wi-Fi); SDGE 56% overall with 22% opt-out, 8% signal failure, 17% equipment not in use during event.

Parameters	Units	Values	Notes
Ramp Rate	Number of years to reach maximum achievable potential	31	Cadmus conservatively estimated 10% smart thermostat saturation in 2023 and 3.3% annual growth in saturation. To inform this, Cadmus relied on data from the Northwest Residential Building Stock Assessment, Wisconsin Focus, and NYSERDA baseline studies. LG&E and KU currently does not offer incentives for smart thermostats, therefore Cadmus assumed smart thermostats saturations conservatively.

Table B-8. Residential HP/AC DLC Existing One-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assumption based on expectation that LG&E and KU's current one-way DLC switches will be phased out in the future.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.
Peak Load Impact	kW per participant (at meter)	Summer: 0.42 Winter: 0.75	Summer: Based on LG&E and KU 2017 SCRAM. Winter: Benchmarking included: SF 0.62 kW and MF 0.47 kW Xcel (2015), MRES (2014) 1.0 kW, Duke Energy Indiana (2015) 1.0-1.5 kW, Duke Energy Ohio (2015) 0.9-1.8 kW, and Duke Energy Carolinas 1.19-1.57 kW. PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH. The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.

Parameters	Units	Values	Notes
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	Summer: 100% Winter: 50%	Summer: Event participation accounted for kW impact SCRAM results - SCRAM kW impact represented [system kW reduction observed]/[count of all distributed switches (regardless of participation)]. Winter: LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-9. Residential HP/AC DLC Existing Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 7.3%, KU: 6%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.

Parameters	Units	Values	Notes
Peak Load Impact	kW per participant (at meter)	Summer: 0.59 Winter: 0.75	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Benchmarking included: SF 0.62 kW and MF 0.47 kW Xcel (2015), MRES (2014) 1.0 kW, Duke Energy Indiana (2015) 1.0-1.5 kW, Duke Energy Ohio (2015) 0.9-1.8 kW, and Duke Energy Carolinas 1.19-1.57 kW. PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH. The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	94%	SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-10. Residential HP/AC DLC New Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$174	Based on discussion with LG&E and KU staff: new switches cost between $100 and $120 with an additional $64 for labor.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$25	Estimated based on MRES (2014) average of $22/customer, Duke Energy Carolina (2015) $32/customer, Duke Energy Ohio and Indiana (2015) $32-67/customer, PSO (2014) $25/CAC + $10/WH, OG&E (2014) same as PSO, and PacifiCorp (2013) $20/CAC + $10/WH.
Attrition	% of existing participants per year	5%	MRES 1% (2014); and PacifiCorp 7% (2012). Thermostat DLC program research ranges from 2% to 9%. CSU assumed 1.5% (2015); MRES 1%; Rocky Mountain Power 2010 had 2%; IPL's 2014-18 plan assumes 3% attrition; Con Edison 2012 program evaluation had 3.8%; Avista thermostat pilot 4%; BPA Kootenai 5% (pilot), Xcel CO thermostat pilot 9% (2013).

Parameters	Units	Values	Notes
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 95% Winter: 23%	Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Summer eligibility based on percent of questionnaire respondents who reported having an air conditioner in their home. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.
Peak Load Impact	kW per participant (at meter)	Summer: 0.59 Winter: 0.75	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Benchmarking included: SF 0.62 kW and MF 0.47 kW Xcel (2015), MRES (2014) 1.0 kW, Duke Energy Indiana (2015) 1.0-1.5 kW, Duke Energy Ohio (2015) 0.9-1.8 kW, and Duke Energy Carolinas 1.19-1.57 kW. PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH. The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.
Program Participation	% of eligible customers	20%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%.
Event Participation	% (switch success rate)	94%	SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	20	Mirrors the 20-year decline of the existing DLC products.

Table B-11.Residential DLC Electric Resistance Water Heater Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 0.5%, KU: 0.4%	Based on observed decline in DLC switch counts from 2017 to 2020.

Parameters	Units	Values	Notes
Eligibility	% of customer count (e.g. equipment saturation)	100%	Customer count was manually adjusted to reflect current water heat switch counts - eligibility for this adjusted customer count is 100%.
Peak Load Impact	kW per participant (at meter)	0.35	PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	50%	LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year. Product ramp rate set to zero from 2028 onwards due to expectation of program cancellation.

Table B-12. Residential DLC Pool Pump Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 6%, KU: 0%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	100%	Customer count was manually adjusted to reflect current pool pump switch counts - eligibility for this adjusted customer count is 100%.
Peak Load Impact	kW per participant (at meter)	1.36	The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	50%	LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year. Product ramp rate set to zero from 2028 onwards due to expectation of program cancellation.

Table B-13. Small Commercial HP/AC DLC Existing One-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assumption based on expectation that LG&E and KU's current one way DLC switches will be phased out in the future.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home. Residential data was used as a commercial proxy.
Peak Load Impact	kW per participant (at meter)	Summer: 0.42 Winter: 1.9	Summer: Based on LG&E and KU 2017 SCRAM. Winter: Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I (1.87 kW) using a ratio of HVAC capacity sizes between small and medium C&I facilities.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	Summer: 100% Winter: 50%	Summer: Event participation accounted for kW impact SCRAM results - SCRAM kW impact represented [system kW reduction observed]/[count of all distributed switches (regardless of participation)]. Winter: LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-14. Small Commercial HP/AC DLC Existing Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative

Parameters	Units	Values	Notes
			costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 7.3%, KU: 6%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home. Residential data was used as a commercial proxy.
Peak Load Impact	kW per participant (at meter)	Summer: 1.1 Winter: 1.9	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I (1.87 kW) using a ratio of HVAC capacity sizes between small and medium C&I facilities.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	Summer: 100% Winter: 94%	Summer: Event participation accounted for kW impact SCRAM results - SCRAM kW impact represented [system kW reduction observed]/[count of all distributed switches (regardless of participation)]. Winter: SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-15. Small Commercial HP/AC DLC New Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative

Parameters	Units	Values	Notes
			costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$174	Based on discussion with LG&E and KU staff: new switches cost between $100 and $120 with an additional $64 for labor.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$25	Estimated based on MRES (2014) average of $22/customer, Duke Energy Carolina (2015) $32/customer, Duke Energy Ohio and Indiana (2015) $32-67/customer, PSO (2014) $25/CAC + $10/WH, OG&E (2014) same as PSO, and PacifiCorp (2013) $20/CAC + $10/WH.
Attrition	% of existing participants per year	5%	MRES 1% (2014); and PacifiCorp 7% (2012). Thermostat DLC program research ranges from 2% to 9%. CSU assumed 1.5% (2015); MRES 1%; Rocky Mountain Power 2010 had 2%; IPL's 2014-18 plan assumes 3% attrition; Con Edison 2012 program evaluation had 3.8%; Avista thermostat pilot 4%; BPA Kootenai 5% (pilot), Xcel CO thermostat pilot 9% (2013).
Eligibility	% of customer count (e.g. equipment saturation)	30%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Peak Load Impact	kW per participant (at meter)	Summer: 1.1 Winter: 1.9	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I (1.87 kW) using a ratio of HVAC capacity sizes between small and medium C&I facilities.
Program Participation	% of eligible customers	10%	Applied (2017): 2.3% - 3.4%; Global (2011): 10%; Brattle (2016): 14%; Navigant (2015a): 1-5%; and Brattle (2014): 15-42%.
Event Participation	% (switch success rate)	94%	SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	20	Mirrors the 20-year decline of the existing DLC products.

Table B-16. Small Commercial DLC Electric Resistance Water Heaters Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 0.5%, KU: 0.4%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	100%	Customer count was manually adjusted to reflect current water heat switch counts - eligibility for this adjusted customer count is 100%.
Peak Load Impact	kW per participant (at meter)	0.35	PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	50%	LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year. Product ramp rate set to zero from 2028 onwards due to expectation of program cancellation.

Table B-17. Residential Behavioral Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per kW pledged per year	$67	BPA assumption (Cadmus 2018) of $89/kW-year (or $4/participant) assumes implementing Res Behavior DR as a stand-alone product. However, Cadmus assumes it would cost $67/kW-year (or $3/participant) to add Res Behavior DR to PSE's existing energy efficiency behavioral program.
Equipment Cost	$ per new kW pledged	$0	Participants must have a device to receive messages.
Marketing Cost	$ per new kW pledged	$0	Included in O&M costs.

Parameters	Units	Values	Notes
Incentives (annual)	$ per kW pledged per year	$0	In line with BPA assumption (Cadmus 2018).
Incentives (one time)	$ per new kW pledged	$0	
Attrition	% of existing participants per year	3%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018).
Eligibility	% of segment/end-use load	100%	AMI dependency captured in ramp rate - eligibility value set to 100%.
Peak Load Impact	% of eligible segment/end-use load	1%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018).
Program Participation	% of eligible segment/end-use load	20%	In line with BPA assumption (Cadmus 2018).
Event Participation	%	100%	Peak load impact percentage accounts for event participation rate.
Ramp Rate	Number of years to reach maximum achievable potential	7	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350 and standard product roll out ramp rate.

Table B-18. Residential CPP without Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	n/a	$0	This product does not provide incentives.
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of segment load	100%	All residential customers are eligible.

Parameters	Units	Values	Notes
Peak Load Impact	% of eligible segment load	Varies by end use	Cadmus (2015): 12%; Cadmus(2017): 12%; Applied (2017): 12.5%; Xcel Energy (2015): 14.8%. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E moved out of pilot to a full program with 20% participation.
Event Participation	n/a	100%	Peak load impact already takes into account of event participation.
Ramp Rate	Number of years to reach maximum achievable potential	8	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-19. Residential CPP with Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI. Enablement technology is assumed to already be installed.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	n/a	$0	This product does not provide incentives.
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of segment load	100%	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	Varies by end use	For cool central, heat central, and heat pump, use 40% based on: Oklahoma (2011) weekday average event day impact for TOU-CP: 38.8%; DTE (2014) average impact during event hours: 44.5%; Nexant (2017b) reported 44.6% for SDG&E. For other end uses, use 12% as consistent with Res CPP-No Enablement. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.

Parameters	Units	Values	Notes
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E moved out of pilot to a full program with 20% participation.
Event Participation	n/a	85%	Peak load impact already takes into account of event participation. But adjusted down for cooling/heating adjustment.
Ramp Rate	Number of years to reach maximum achievable potential	30.5	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350 and on smart thermostat growth. Cadmus conservatively estimated 10% smart thermostat saturation in 2023 and 3.3% annual growth in saturation. To inform this, Cadmus relied on data from the Northwest Residential Building Stock Assessment, Wisconsin Focus, and NYSERDA baseline studies. LG&E and KU currently does not offer incentives for smart thermostats, therefore Cadmus assumed smart thermostats saturations conservatively.

Table B-20. Residential CPR without Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	$ per kWh	$1.10	Incentive cost based a $/kWh incentive range of $0.95 to $1.25 from Consumer Energy and Baltimore Gas and Electric: https://www.bge.com/SmartEnergy/ProgramsServices/Pages/SmartEnergyRewards.aspx and https://peakpowersavers.com/time
Incentives (one time)	n/a	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assuming similar to CPP.
Eligibility	% of segment load	100%	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	Varies by end use	Cadmus (2015): 12%; Cadmus(2017): 12%; Applied (2017): 12.5%; Xcel Energy (2015): 14.8%. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E

Parameters	Units	Values	Notes
			moved out of pilot to a full program with 20% participation.
Event Participation	n/a	100%	Peak load impact already takes into account of event participation.
Ramp Rate	Number of years to reach maximum achievable potential	7	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-21. Residential CPR with Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI. Enablement technology is assumed to already be installed.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	$ per kWh	$1.10	Incentive cost based a $/kWh incentive range of $0.95 to $1.25 from Consumer Energy and Baltimore Gas and Electric: https://www.bge.com/SmartEnergy/ProgramsServices/Pages/SmartEnergyRewards.aspx and https://peakpowersavers.com/time
Incentives (one time)	n/a	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assuming similar to CPP.
Eligibility	% of segment load	1	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	Varies by end use	For cool central, heat central, and heat pump, use 40% based on: Oklahoma (2011) weekday average event day impact for TOU-CP: 38.8%; DTE (2014) average impact during event hours: 44.5%; Nexant (2017b) reported 44.6% for SDG&E. For other end uses, use 12% as consistent with Res CPP-No Enablement. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E moved out of pilot to a full program with 20% participation.
Event Participation	n/a	85%	Peak load impact already takes into account of event participation. But adjusted down for cooling/heating adjustment.

Parameters	Units	Values	Notes
Ramp Rate	Number of years to reach maximum achievable potential	30.5	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-22. Residential Time of Use Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$0	Assume program is new rate class and requires minimal additional maintenance.
Equipment Cost	$ per new participant	$0	No equipment needed to participate
Marketing Cost	$ per new participant	$30	Based on one-half FTE of staff time valued at $50/hour (fully-loaded) with an additional 25% to reflect additional effort.
Incentives (annual)	n/a	$0	This product does not provide incentives.
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	2%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of segment load	100%	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	10%	LG&E KU's price ratio of 4.07 equated to a 7% to 9% potential on a program price responsiveness curve. Benchmarking of summer programs includes: 7.4% Xcel (2015); 8% PSO (2014); 9% SMUD (2014); Nevada Energy 10.74% (2015); 14% OG&E.
Program Participation	% of eligible segment load	20%	Participation estimates align with recent Xcel Energy's price responsiveness survey and program benchmarking. Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters): SMUD had a significant pilot that reached 5%; TVA potential 5%. OG&E moved out of pilot to a full program with 20%. PGE potential used 2% increasing to 40% in 2028;
Event Participation	n/a	100%	Event participation is captured in the average load impact.
Ramp Rate	Number of years to reach maximum achievable potential	9	Based on uptake of rate program and on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Appendix C. Supplemental Results Figures and Tables

The figures and tables below show supplemental summaries of the results presented.

Figure C-1. DLC Products - Summer Market Potential

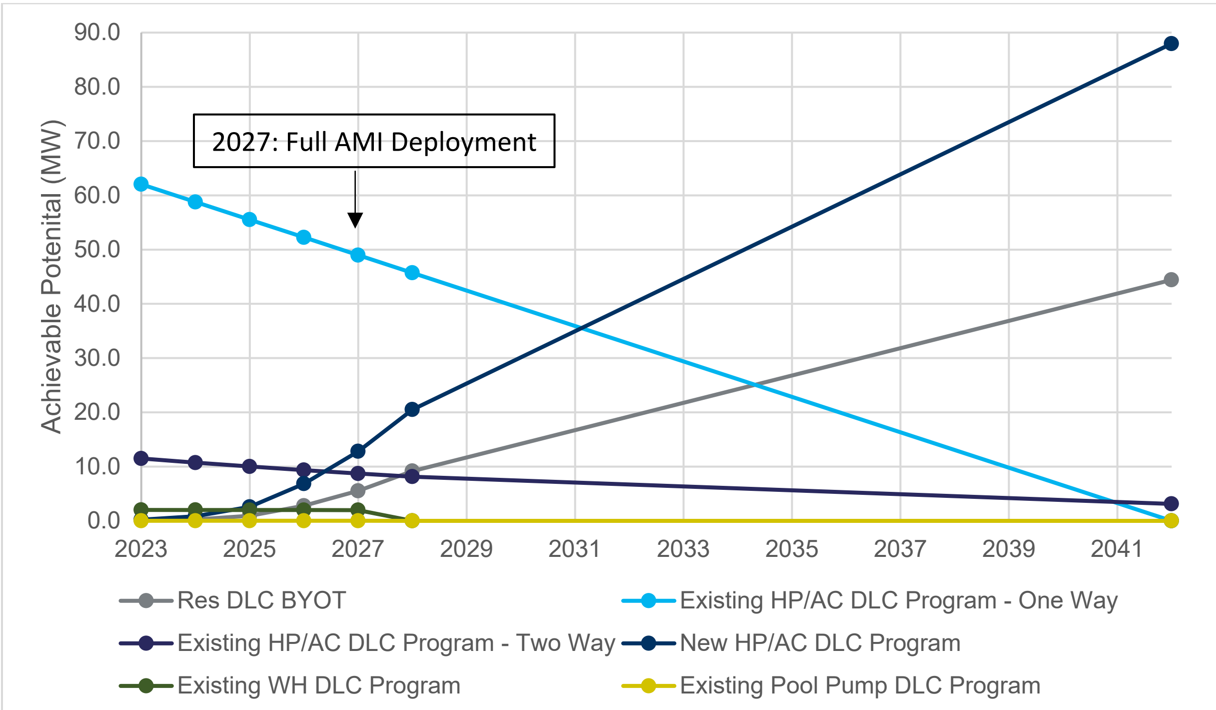


Figure C-2. Curtailment Products - Summer Market Potential

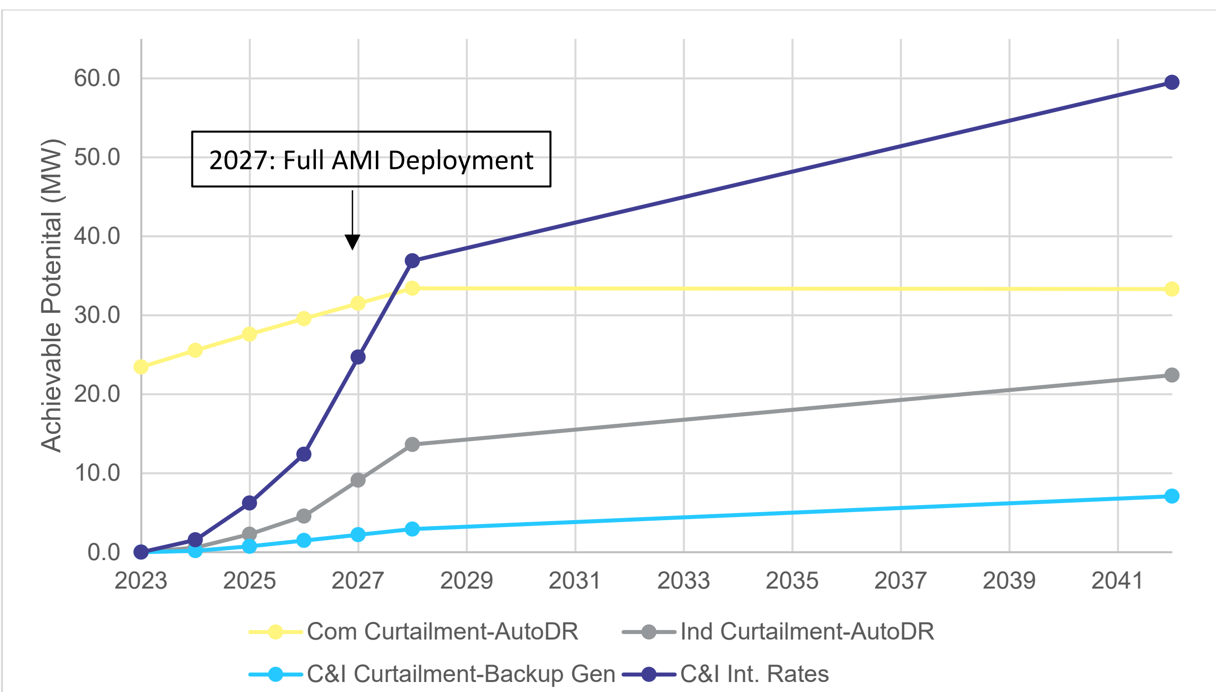


Figure C-3. Pricing/Other Products - Summer Market Potential

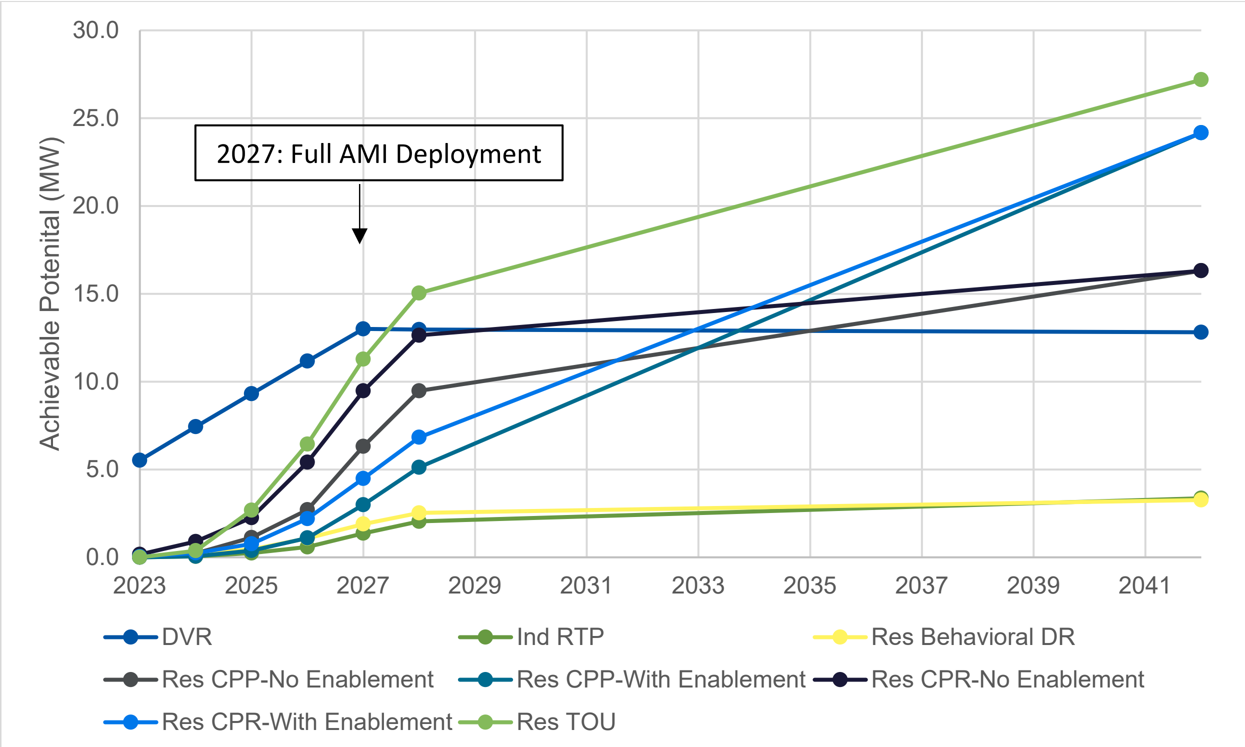


Figure C-4. DLC Products - Winter Market Potential

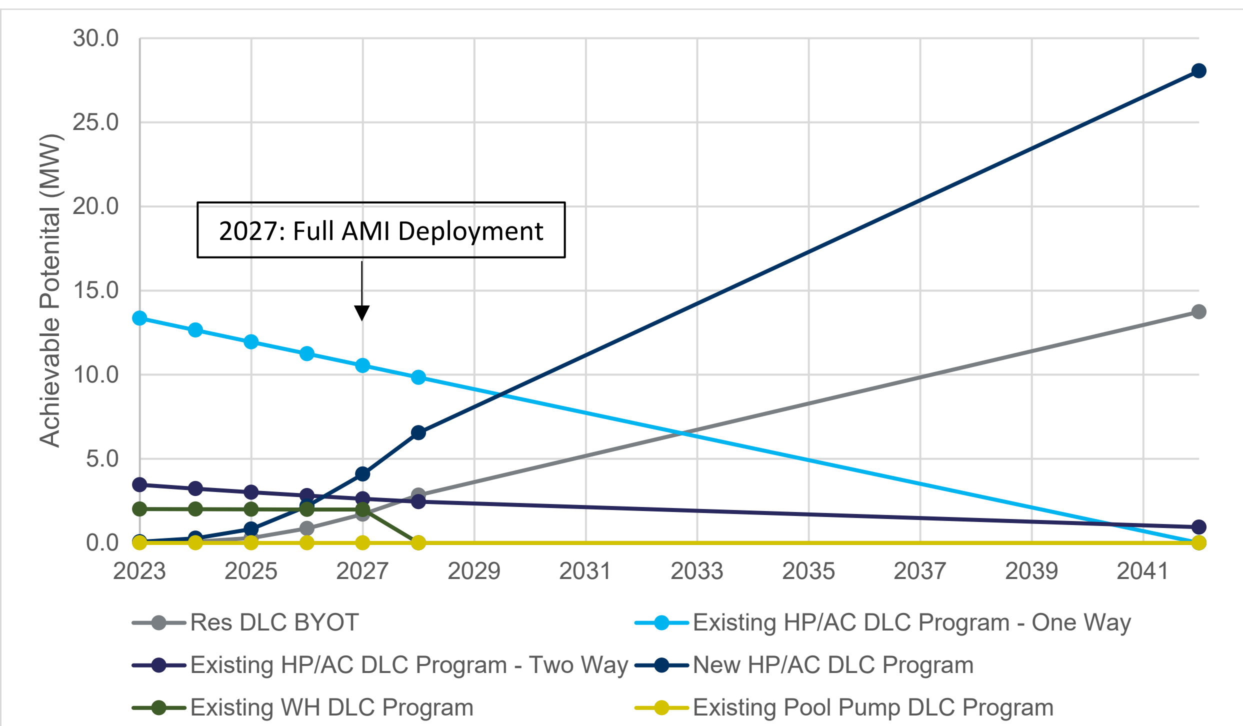


Figure C-5. Curtailment Products - Winter Market Potential

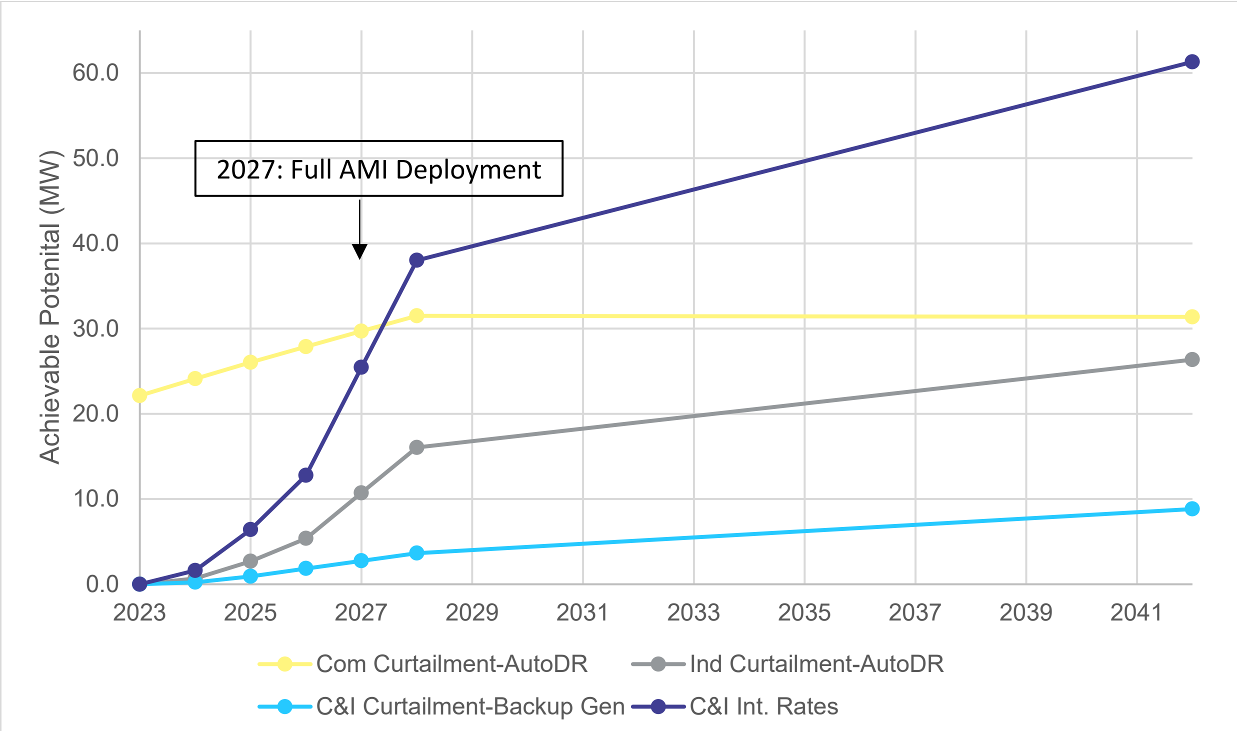


Figure C-6. Pricing/Other Products - Winter Market Potential

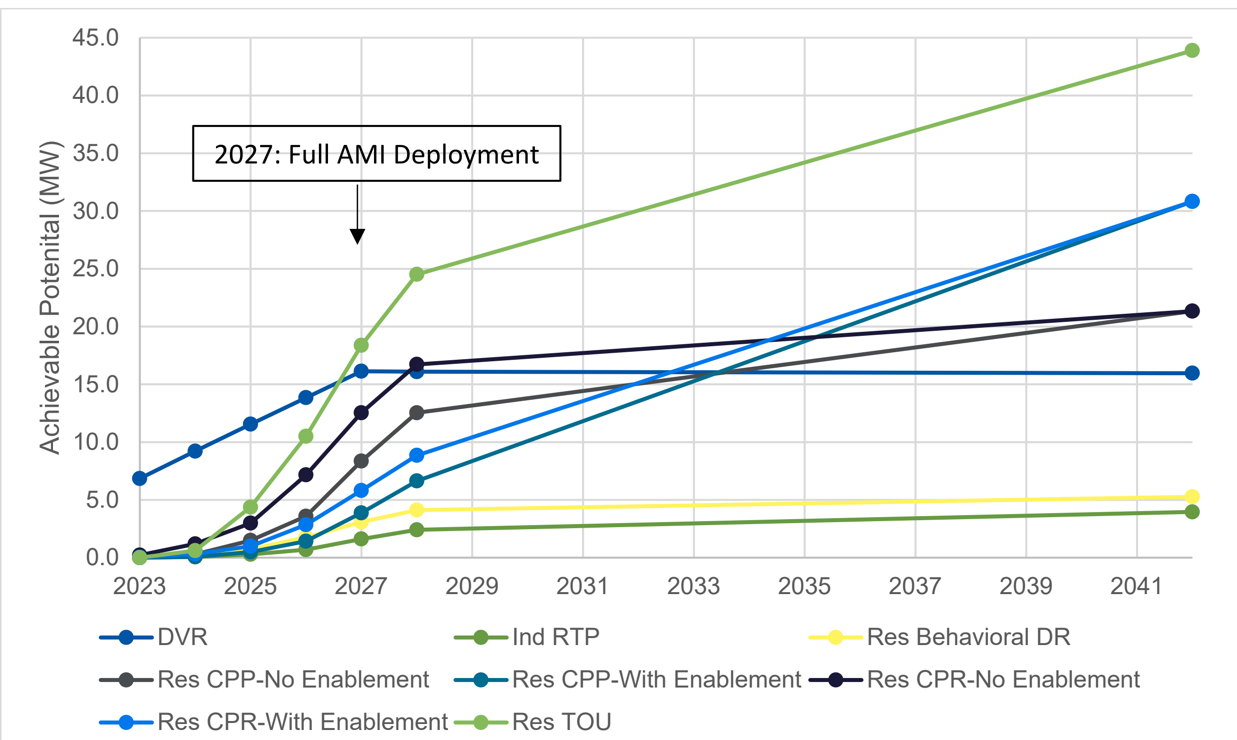


Table C-1. Cost-Effectiveness Results

Product	Benefit-Cost Ratio	
	Summer	Winter
C&I Curtailment-Backup Gen	0.30	0.37
Existing WH DLC Program	0.48	0.48
New HP/AC DLC Program	0.77	0.99
Res DLC BYOT	0.85	1.04
Ind RTP	1.22	1.43
Existing HP/AC DLC Program - One Way	1.15	1.06
Res Behavioral DR	1.21	1.25
Existing HP/AC DLC Program - Two Way	1.55	2.00
Ind Curtailment-AutoDR	1.91	2.16
Existing Pool Pump DLC Program	1.89	N/A
Res CPR-No Enablement	2.42	2.84
Res CPR-With Enablement	2.55	2.48
Res CPP-No Enablement	2.74	3.62
Com Curtailment-AutoDR	2.99	2.62
Res CPP-With Enablement	3.38	4.35
Res TOU	4.33	7.04
C&I Int. Rates	8.28	8.44
DVR	9.44	9.67

Table C- 2. Tipping Point Analysis Results

Product	Tipping Point Cost	
	Summer	Winter
C&I Curtailment-Backup Gen	$320	$257
Existing WH DLC Program	$183	$183
New HP/AC DLC Program	$114	$89
Res DLC BYOT	$103	$84
Ind RTP	$78	$66
Existing HP/AC DLC Program - One Way	$76	$83
Res Behavioral DR	$73	$70
Existing HP/AC DLC Program - Two Way	$57	$44
Ind Curtailment-AutoDR	$50	$44
Existing Pool Pump DLC Program	$47	N/A
Res CPR-No Enablement	$36	$31
Res CPR-With Enablement	$35	$35
Res CPP-No Enablement	$35	$26
Com Curtailment-AutoDR	$29	$34
Res CPP-With Enablement	$28	$22
Res TOU	$22	$13
C&I Int. Rates	$11	$11
DVR	$9	$9

Exhibit LI-3

The supporting calculations for KU’s DSM cost recovery mechanism are being provided as a separate file in Excel format.

Exhibit LI-4

The supporting calculations for LG&E’s electric DSM cost recovery mechanism are being provided as a separate file in Excel format.

Exhibit LI-5

The supporting calculations for LG&E's gas DSM cost recovery mechanism are being provided as a separate file in Excel format.

Exhibit LI-6

Information in the exhibit is confidential and proprietary and is provided under seal pursuant to a petition for confidential protection. In addition, portions of the exhibit are voluminous and are provided pursuant to a motion to deviate.