STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	))))))	**DIRECT TESTIMONY OF TIMOTHY J. DUFF AND JONATHAN L. BYRD ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND OVERVIEW

Q. MR. DUFF, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION ("DUKE ENERGY").

A. My name is Timothy J. Duff, and my business address is 400 S. Tryon Street, Charlotte, North Carolina, 28202. I am the General Manager, Grid Strategy Enablement for Duke Energy Business Services, LLC ("DEBS").

Q. BEFORE INTRODUCING YOURSELF FURTHER, WOULD YOU PLEASE INTRODUCE THE PANEL?

A. Yes. I am appearing on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies") together with Jonathan Byrd on the "Grid Edge and Customer Programs Panel." Witness Byrd will introduce himself.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Michigan State University with a Bachelor of Arts in Political Economics and a Bachelor of Arts in Business Administration and received a Master of Business Administration degree from the Stephen M. Ross School of Business at the University of Michigan.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I started my career with Ford Motor Company and worked in a variety of roles within the company's financial organization, including Operations Financial

Analyst and Budget Rent-A-Car Account Controller. After five years at Ford Motor Company, I started working with Cinergy in 2001, providing business and financial support to plant operating staff. Eighteen months later, I joined Cinergy's Rates Department, where I provided revenue requirement analytics and general rate support for the company's transfer of three generating plants. After my time in the Rates Department, I spent a brief time in the Environmental Strategy Department, and then I joined Cinergy's Regulatory and Legislative Strategy Department. After Cinergy merged with Duke Energy in 2006, I served as Managing Director, Federal Regulatory Policy for four years. In that role, I was primarily responsible for developing and advocating for Duke Energy's policy positions with the Federal Energy Regulatory Commission. In 2010, I was named General Manager, Energy Efficiency & Smart Grid Policy and Collaboration. Since 2010, I have held a number of positions related to analyzing and gaining regulatory approval of customer product and service offerings, including energy efficiency ("EE") and demand response. I assumed my current position in April 2021.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for the development of strategies and policies related to the implementation of EE and other retail products and services that create customer and utility system value. I also oversee the analytics functions associated with evaluating and tracking the performance of Duke Energy's

Integrated Grid Solution retail products and services. My responsibilities cover all of Duke Energy's utility operating companies, including DEC and DEP.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. For more than a decade, I have testified before the North Carolina Utilities Commission ("NCUC" or "Commission") on numerous occasions as an expert witness with respect to the EE and demand-side management ("DSM") portfolios. I also testified as an expert witness on the Companies' Grid Edge programs in the 2022 Carbon Plan proceeding in Docket No. E-100, Sub 179 ("2022 Carbon Plan Proceeding").

Q. MR. BYRD PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY.

A. My name is Jonathan L. Byrd, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202. I am the Managing Director of Rate Design and Regulatory Solutions for Duke Energy Business Solutions ("DEBS"). DEBS is a service company subsidiary of Duke Energy that provides services to Duke Energy and its subsidiaries, including DEC and DEP.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of North Carolina ("UNC") at Charlotte, a Master of Engineering degree from North Carolina State University, and a Master of Business Administration degree from UNC-Chapel Hill.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I joined Duke Energy in 2005 and have worked in various roles including large business customer products and services, corporate finance, and renewable energy. In June of 2020, I moved into my current role in Pricing and Regulatory Solutions.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. My responsibilities include creating new pricing designs across all Duke Energy jurisdictions as well as implementing rate tariffs, administration and filings, and contracts. I also interact with stakeholders on these matters and assist in seeking associated regulatory approvals.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NCUC?

A. Yes. I have appeared before the NCUC on several occasions, including recently on behalf of DEP in its most recent general rate case in Docket No. E-2, Sub 1300.

Q. IS THE PANEL SPONSORING ANY EXHIBITS?

A. Yes. The Panel is sponsoring the updated North Carolina Market Potential Study performed by Resource Innovations, Inc. (the “2023 MPS” and “Resource Innovations”). The updated North Carolina 2023 MPS is included as Exhibit 1 to this Panel’s testimony.

Q. MR. DUFF, ON BEHALF OF THE PANEL, PLEASE BRIEFLY DESCRIBE THE PURPOSE OF THE PANEL'S TESTIMONY.

A. This Panel's testimony provides an overview of the Companies' Grid Edge and Customer Program efforts that support the Carbon Plan and Integrated Resource Plan ("CPIRP" or "the Plan") and respond to the NCUC's directives in its December 30, 2022, Order Adopting Initial Carbon Plan and Providing Direction for Future Planning in Docket E-100 Sub 179 ("Carbon Plan Order").[1] Grid Edge refers to technologies, programs, and investments that advance a decentralized, distributed, and two-way grid. The "edge" refers to the edge of the electricity network, or grid, where the Companies' electricity reaches customers' homes and businesses. The Companies remain regional and nationwide leaders in delivering energy savings for our customers and are at the forefront of the Grid Edge evolution and innovative new customer programs. As explained in the Executive Summary of the Companies' CPIRP, the Companies continue to prioritize "shrinking the challenge" by reducing energy requirements and modifying load patterns through Grid Edge and customer programs, allowing more tools to respond to fluctuating energy supply and demand, and enabling customers to better manage their energy usage.

For purposes of CPIRP modeling and consistent with the Carbon Plan Order, the Companies modeled a base case assumption of a minimum annual reduction of 1% of eligible load from EE savings, as well as a sensitivity

[1] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No. E-100, Sub 179 at 133-34 (Ordering Paragraph Nos. 27-32) (Dec. 30, 2022) ("Carbon Plan Order").

assuming annual savings floor of 1.5% of eligible retail sales.[2]

The Panel will also discuss the actions taken by the Companies to advance the potential enablers identified by the Companies as necessary to deliver the levels of energy savings forecasted by the Companies. The Companies have also reviewed and provided updates to the forecasted contributions of the other Grid Edge and customer programs factored into the updated CPIRP.

Q. PLEASE EXPLAIN HOW THE REMAINDER OF THIS PANEL'S TESTIMONY IS ORGANIZED.

A. Section II of the Panel's testimony identifies the portions of the Plan and the Companies' Requests for Relief presented to the Commission for approval in support of the Plan that this Panel sponsors.

Section III of the testimony discusses Grid Edge's role in the CPIRP, including (1) significant updates since the NCUC's Carbon Plan Order, (2) impacts of the Inflation Reduction Act ("IRA"), (3) the challenges to achieving 1% of annual eligible load utility energy efficiency ("UEE") savings, (4) demand response, and (5) voltage optimization.

Section IV of the testimony discusses the Companies' rate design efforts relevant to the CPIRP, including (1) rate design modernization, (2) load impacts from rate design, and (3) electric vehicle pilots and programs.

Section V of the testimony discusses customer clean energy programs.

[2] *See* Carbon Plan Order at 133-34 (Ordering Paragraph No. 28).

II. SPONSORSHIP OF THE PLAN

Q. MR. DUFF, WHAT SECTIONS OF THE CPIRP IS THIS PANEL SPONSORING THROUGH ITS DIRECT TESTIMONY?

A. The Grid Edge and Customer Programs Panel adopts and sponsors those parts of the CPIRP describing the Companies' Grid Edge and customer programs initiatives, as follows:

- Chapter 3, Portfolios. This Chapter provides details on portfolio composition (resource decisions) and comparative evaluations across pathways and portfolios for the CPIRP. This Panel sponsors the aggressive underlying assumptions related to Grid Edge programs and the modeling results in Chapter 3.
- Chapter 4, Execution Plan. This Chapter provides a detailed roadmap and reflects an intentional evolution of the short-term action plan framework presented in the Companies' past integrated resource plans. This Panel sponsors the near-term execution plans contained in this chapter for Grid Edge and Customer Programs.
- Appendix C, Quantitative Analysis. This Appendix outlines the modeling and quantitative analysis performed to develop the Core Portfolios, Portfolio Variants, and Sensitivity Analysis Portfolios. This Panel sponsors the portion of Appendix C that discusses the UEE and other Grid Edge and customer program inputs into the modeling.
- Appendix H, Grid Edge and Customer Programs. This Appendix outlines the Companies' ongoing efforts to provide customers with a

variety of options to manage their electric use to both reduce monthly bills and provide value to the electric grid. This Panel sponsors the entire Appendix.

Q. PLEASE IDENTIFY THE REQUESTS FOR RELIEF PRESENTED IN THE COMPANIES' CPIRP PETITION AND BOWMAN EXHIBIT 1 THAT THE PANEL IS SUPPORTING THROUGH ITS TESTIMONY.

A. The Panel supports CPIRP Request for Relief 1 as in the public interest and requests Commission approval as a necessary and reasonable step to execute the CPIRP during the near-term. Specifically, this Panel supports Request for Relief 1 with respect to the 1% of eligible load annual EE savings being used as an annual floor or minimum for the magnitude of the load modifier included in the CPIRP modeling. As outlined in Appendix H and discussed further in this testimony, the Companies face numerous challenges in reaching the 1% of eligible load annual EE savings going forward; however, with the approval of proposed enablers, the Companies believe that it is an aggressive, but achievable goal.

Q. DO THE COMPANIES HAVE ANY ADDITIONAL REQUESTS WITH RESPECT TO THEIR GRID EDGE AND CUSTOMER PROGRAMS GOING FORWARD?

A. Yes. Consistent with CPIRP Request for Relief 5 in Bowman Exhibit 1, the Companies request that the NCUC find and conclude that the Companies' plan to continue advancing their Grid Edge and customer programs is reasonable and appropriate. To that end, with respect to EE programs and savings, the

Companies also request that the NCUC direct them to continue to engage with stakeholders in revising the DSM/EE Cost Recovery Mechanism to reflect the four enablers discussed in the NCUC's Carbon Plan Order, including revising the underlying determination of the utility system benefits in approved EE/DSM Cost Recovery Mechanism to more accurately reflect the value of these important Grid Edge resources, which is foundational to the Companies' ability to cost-effectively expand EE/DSM offerings to customers.

Q. MR. DUFF, PLEASE EXPLAIN GRID EDGE PROGRAMS.

A. Grid Edge refers to technologies, programs, and investments that advance a decentralized, distributed, and two-way grid focusing on the "edge" or the point on the grid where the Companies deliver electricity to customers' homes and businesses. Grid Edge programs include certain rate designs, voltage control efforts, and other customer programs, such as EE and DSM programs, renewable energy programs and electric transportation programs, and voltage optimization. Now more than ever, customers can more directly manage and impact their use of electricity, and Grid Edge programs are intended to offer customers options to do so. The Companies' Grid Edge programs typically come before the NCUC for review and approval in other dockets; for example, the NCUC recently approved DEP's weatherization program intended to assist low-income customers reduce their energy use in Docket No. E-2, Sub 1259 and the Companies' net metering tariffs in Docket No. E-100, Sub 180.[3] Collectively, however, these programs and initiatives play a critical role in the

[3] Order Approving Revised Net Metering Tariffs, Docket No. E-100, Sub 180 (Mar. 23, 2023).

CPIRP because they empower customers and the Companies with a variety tools to manage electric usage during the energy transition, resulting in potentially lower monthly bills, added value to the grid, and cleaner energy use.

III. GRID EDGE'S ROLE IN THE PLAN

Q. PLEASE DISCUSS HOW THE COMPANIES' GRID EDGE PROGRAMS FACTOR INTO THE CORE OBJECTIVES OF THE CPIRP—PLANNING FOR AN ORDERLY ENERGY TRANSITION AND INCREASINGLY CLEAN RESOURCE MIX.

A. As described in the Companies' CPIRP, the Companies' approach to an orderly and least cost transition toward a clean energy future continues to rely on "shrinking the challenge." As explained in greater detail throughout this testimony and in Appendix H, the Companies utilize Grid Edge and customer programs to "shrink the challenge" by focusing on reducing and shifting the load the Companies must serve, and adding to and enhancing an increasingly clean resource mix. Grid Edge and customer programs aid in these load reduction efforts by enabling investments and offering programs such as EE, DSM, voltage management, and other distributed energy resources ("DER").

Q. TURNING TO THE COMPANIES' SPECIFIC EE AND DSM EFFORTS, HAVE THE COMPANIES INCORPORATED STAKEHOLDER INPUT IN THEIR EE/DSM TARGETS AND PROGRAM OFFERINGS?

A. Yes. The Companies have long recognized the considerable benefit in regularly working with the stakeholders through the EE/DSM Carolinas Collaborative ("Collaborative"). Working with the Collaborative has been key to enabling the

Companies to successfully offer customers robust suites of EE/DSM programs for well over a decade. The Collaborative continues to inform the Companies' EE/DSM efforts through its continued mission to act as "a forum for providing insight and input concerning topics related to energy efficiency and demand-side management including program design and development; measurement and evaluation; regulatory and market conditions; specific issues or topics as requested by the [NCUC] and the Public Service Commission of South Carolina; and emerging opportunities to achieve cost-effective energy savings."[4] For example, the Collaborative, which began in 2009, has met regularly to discuss programs and offerings such as the recently-filed addition of the storage measure to the PowerManager and EnergyWise Home Demand Response programs.[5] More specifically, the Collaborative has met multiple times over the past 12 months to discuss the development of the Companies' most recent 2023 MPS, which informed the Companies' long term EE forecasts. In these meetings, members provided feedback regarding (i) the development of EE measures to be analyzed and (ii) the updated methodology used in determining customer adoption necessary for determining achievable EE savings potential. The Collaborative continues to seek opportunities to enhance existing programs and address the current challenging market conditions.

[4] Carolinas DSM/EE Collaborative, https://www.duke-energy.com/our-company/environment/carolina-collaborative (last visited Aug. 31, 2023).

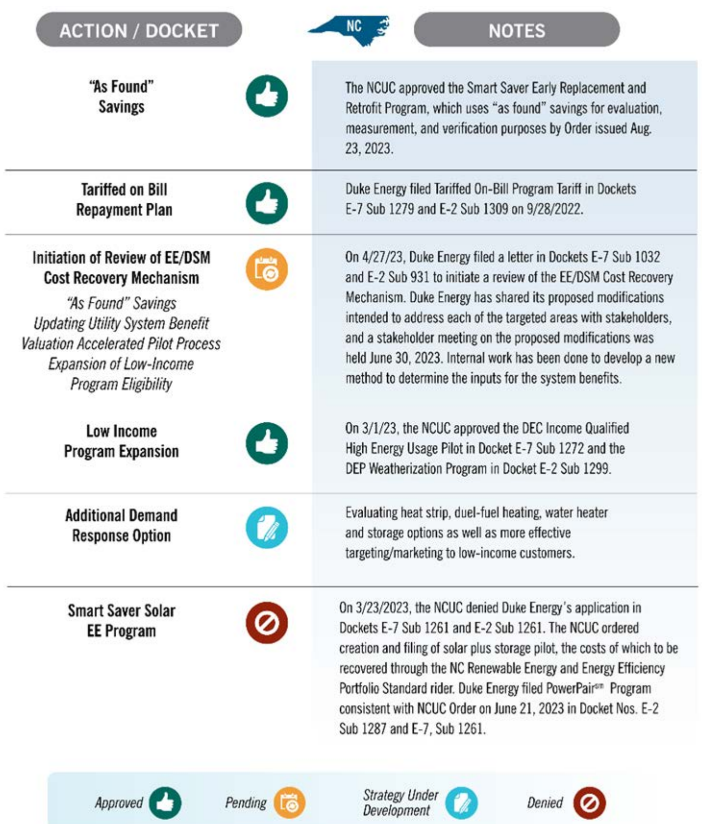
[5] Proposed Modifications to the Existing Commission-Approved Residential Power Manager Load Control Service, Docket No. E-7, Sub 1032 (June 21, 2023) ("Proposed Modifications to Power Manager"); Proposed Modifications to the Existing Commission-Approved Residential Service Load Control Rider LC-9, Docket No. E-2, Sub 927 (June 21, 2023) ("Proposed Modifications to EnergyWise").

A. Significant Updates from the 2022 Carbon Plan

Q. MR. DUFF, CAN YOU UPDATE THE NCUC ON THE STATUS OF THE COMPANIES' PROPOSED "ENABLERS" FOR EE AND DSM PROGRAMS SINCE THE INITIAL PROPOSED CARBON PLAN?

A. Yes. In the 2022 Carbon Plan Proceeding, the Companies proposed enablers that were necessary for the Companies to achieve an aggressive 1% of annual eligible load savings target. As discussed in more detail in Appendix H, these enablers essentially expand the Companies' ability to offer more cost-effective EE programs to more customers. The status of these enablers since the NCUC's Carbon Plan Order is outlined in Figure 1 below.

Figure 1 – Enabler Status Update



Q. CAN YOU PROVIDE ADDITIONAL DETAIL ON THE STATUS OF THE REVIEW OF THE EE/DSM COST RECOVERY MECHANISM?

A. Yes. In its Carbon Plan Order, the Commission directed the Companies to initiate a review of the DSM/EE cost recovery mechanisms to consider the enablers the Companies had proposed, including: (i) updating the inputs underlying the cost benefit test in the mechanisms; (ii) using the as-found baseline for EE measures; (iii) changing the definition of low-income customer; and (iv) developing guidelines for expedited regulatory approval of DSM/EE pilot programs.[6]

In April 2023, consistent with the Commission's Carbon Plan Order, the Companies filed a letter with the Commission to initiate this review of the DSM/EE Mechanism with a proposed timeline to allow for stakeholder input and for the impacts of the proposed revisions to take effect in 2025. The Companies plan to implement expansion of their EE and DSM offerings to customers as soon as the necessary modifications are approved. The Companies have met with stakeholders in June to share proposed revisions necessary to implement the four enablers specifically referenced in the Commission Order and have solicited input on both alternative and additional modifications. Stakeholders have not provided any substantive input at this time. The Companies remain committed to stakeholder engagement on, and obtaining Commission approval of, this critical step so that they will be able to expand their EE and DSM offerings to customers in 2025. To that end, the Companies

[6] Carbon Plan Order at 134 (Ordering Paragraph No. 31).

are working to obtain stakeholder feedback on their proposed revisions, with a goal of putting those revisions before the Commission for its review in early October 2023. Although the NCUC has recently reaffirmed its acceptance of the use of the "as found" savings enabler in its approval of the Companies' Smart Saver Retrofit program and Tariffed on Bill Repayment Plan enabler, revising the DSM/EE Mechanism as proposed by the Companies remains critical to achieving the aggressive long-term 1% annual energy savings of eligible load floor. The DSM/EE Cost Recovery Mechanism provides clarity and certainty to the Companies' ability to plan and implement their DSM/EE portfolio, and the Companies proposed revisions to it, once approved, will allow the Companies to offer more customers more cost-effective EE and DSM options.

Q. ARE THERE ANY OTHER SIGNIFICANT UPDATES TO THE COMPANIES' EE AND DSM EFFORTS SINCE THE 2022 CARBON PLAN PROCEEDING?

A. Yes. The Companies have an updated 2023 MPS which is attached to this Panel's testimony as Exhibit 1.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THIS UPDATED 2023 MPS.

A. As discussed in Appendix H, the Companies' updated 2023 MPS was performed by an independent third party, Resource Innovations, with the engagement of the Carolinas EE/DSM Collaborative. In addition to the standard updates related to efficiency standards and efficiency measures available, three significant updates to this year's 2023 MPS methodology differed from previous market potential studies. First, the 2023 MPS evaluated the economic potential utilizing the Utility Cost Test ("UCT"). The UCT is a cost-effectiveness test that measures the net costs of a DSM or EE program as a resource option based on the costs incurred by the utility (including incentive costs paid by the utility to or on behalf of participants) and excluding any net costs incurred by the participant. The benefits for the UCT are avoided supply costs, i.e., the reduction in generation capacity costs, transmission and distribution costs, and energy costs caused by a load reduction.[7] Second, the basis for customer adoption assumptions for EE and DSM programs in prior market potential studies had used an achievable "real world" potential that typically recognized existing customer economic, market, *and* behavioral barriers to adoption. In this 2023 MPS, customer adoption assumptions were modified to focus only on customer economic barriers to adoption and applied customer payback acceptance curves to calculate a measure's long-run market share relative to competing EE measures, which is a more aggressive assumption approach. The 2023 MPS also sought to assess the potential impact of the unprecedented amount of federal dollars available related to EE rebates due to the 2022 IRA. While many of the details of the EE-related funding opportunities in the IRA continue to be finalized, the impact over the 10-year duration of the IRA funding is forecasted to lead to a significant increase

[7] This update was necessitated by the NCUC's approval of the most recent DSM/EE Cost Recovery Mechanism, which went into effect in 2022.

EE/DSM savings potential by increasing customer adoption. This increase can be seen in Figures 2 and 3 below.

Q. PLEASE DISCUSS THE MAGNITUDE OF THE CHANGE THAT THE UPDATED 2023 MPS HAD ON THE COMPANIES' UEE FORECAST.

A. The Companies modeled these changes over the 28-year period covered in the Plan. The Companies' base case forecast using a 1% of eligible load minimum annual savings floor saw the total amount of annual energy savings increase by over 4,900 GWH with annual EE savings over the 28-year period increasing by over 11% for DEP and over 18% for DEC between the 2022 and 2023 forecasts. In the high EE sensitivity modeled with the energy savings at 1.5% of eligible load annual, the total amount of annual energy savings increased by over 4,000 GWH, with annual EE savings over the 28-year period increasing by over 5.5% for DEP and over 12% for DEC between the 2022 and 2023 forecasts.

B. IRA Impacts on UEE

Q. PLEASE EXPLAIN HOW THE COMPANIES' UEE FORECAST ACCOUNTED FOR THE POTENTIAL IMPACTS OF THE IRA ON CUSTOMER INVESTMENT IN UEE?

A. The passage of the IRA will make approximately $360 billion available to spur investments to reduce greenhouse gas emissions and combat climate change. Included in this funding are the following federal programs designed to promote EE investments:

- Home energy performance-based whole-house (HOMES) rebates;
- Energy efficient commercial building deduction;

- High-efficiency electric home rebate program; and
- Energy Efficient Home Improvement Credit.

The Companies utilized Resource Innovations to develop the 2023 MPS modeling scenarios around the potential magnitude the programs could have on achievable market potential. At the time of performing modeling, Resource Innovations only had preliminary guidance from the United States Department of Energy on specific programmatic details, which creates a substantial amount of uncertainty regarding how the programs will ultimately be implemented by the participating states. Despite the uncertainty, Resource Innovations was able to create a supplemental list of measures and the associated costs that was used to update the model to estimate the potential impacts. The result of the modeling suggests that the IRA will likely increase the amount of EE potential and expedite the market acceptance of related EE technologies, leading to increased adoption of these technologies. In fact, the modeling indicates that the IRA will increase cumulative achievable market potential by 28% in 2027, 34% by 2032, and 38% by 2047. These estimates also assume the IRA rebates will sunset after 10 years and will no longer be available by 2033. These assumptions are already built into the CPIRP modeling. Given the Companies' desire and significant efforts to ensure that its utility EE programs are coordinated and complimentary to the State Energy Office's plans to administer the IRA programs, the Companies believe that a sizeable amount of the IRA's impact to achievable potential will be realized as UEE. The Companies' UEE Forecasts assume that 60% of the IRA impact will come through UEE, meaning that 40% of the projected IRA impact has been reflected as naturally occurring EE in the load forecast.

C. Challenges to Achieving 1% of Annual Eligible Load UEE Savings

Q. MR. DUFF, EVEN WITH THAT INCREASE IN POTENTIAL UEE SAVINGS RESULTING FROM THE IRA, DO YOU HAVE ANY CONCERNS ABOUT THE COMPANIES' UEE FORECAST?

A. The Companies believe that the application of an assumed annual floor or minimum amount of UEE savings, based on a percentage of eligible load, in the EE forecast may lead to overly aggressive long-term EE forecasts.

Q. CAN YOU EXPLAIN WHAT "ELIGIBLE LOAD" INCLUDES FOR PURPOSES OF THE UEE FORECAST?

A. Yes. Because the Companies cannot offer EE programs to all customers or claim EE savings related to all of their respective loads, "eligible load" refers to the load resulting from residential and non-residential retail customers who participate in the Companies' EE programs and do not opt-out of the EE/DSM rider as permitted by N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-68(d). In other words, currently over 35% of the Companies' total retail load is opted out of the rider; therefore, their energy savings are not attributable to the Companies' EE programs.

Q. DOES THE INCREASE IN THE LOAD FORECAST FROM THE 2022 CARBON PLAN PROCEEDING IMPACT THE COMPANIES' ELIGIBLE LOAD?

A. Yes. As discussed in Appendix H, contrasting the amount of load growth from the initial proposed Carbon Plan filing with this CPIRP highlights the significance of what is included in eligible load for purposes of achieving energy savings of 1% of eligible load annually. As the Companies have reported, favorable economic development, residential population growth and the increasing adoption of electric vehicles ("EV") are driving dramatic load growth in the Carolinas, effectively increasing the amount of MWh savings needed to meet the 1% annual floor. Two of those drivers of increased load—favorable economic development bringing large commercial and industrial customers to the Carolinas and the increasing adoption of EVs—present little opportunity for the Companies to find EE savings. For example, the large industrial and commercial customers locating in the Carolinas due to economic development will likely be building at a highly efficient level and will also be eligible to opt out of participating in the Companies' EE programs. Additionally, EV adoption by residential and non-residential customers will increase energy usage. Although the Companies have developed demand-side management programs, like DEC's Vehicle-to-Grid ("V2G") Pilot,[8] and pricing structures like its Managing Charging Subscription Pilots[9] to allow the Companies to reduce a customer's EV charging during peak periods to help manage the grid and maintain reliability, the Companies do not have EE programs that achieve overall energy savings from charging EVs. Thus, future

[8] Order Approving Pilot Program Subject to Conditions, Docket No. E-7, Sub 1275 (Apr. 11, 2023).

[9] Order Approving Electric Managed Charging Pilot Programs, Docket Nos. E-2, Sub 1291 and E-7, Sub 1266 (June 24, 2022).

inclusion of such forecasted load in eligible load creates an unrealistic and unattainable long-term forecast of EE savings because, although their inclusion effectively increases the amount of MWh savings needed to meet the 1% annual floor, there are currently no utility EE measures to achieve savings from that additional load. As I have discussed, the Companies expect higher EE savings over the next decade due to IRA rebates. Those rebates are time-bound, however, and will eventually end, causing the EE forecast to decline to the 1% of eligible load for the remaining time horizon, as shown in Figures 2 and 3.

Q. MR. DUFF, TAKING THOSE CONCERNS INTO ACCOUNT, DOES THE 1% ANNUAL UEE SAVINGS FLOOR REMAIN REASONABLE AND APPROPRIATE FOR USE IN RESOURCE PLANNING?

A. Yes. While the Companies are enthusiastically embracing EE to "shrink the challenge" and are incented to achieve as much EE savings as possible, in as cost-effective manner possible, they believe that the existing forecasted level of energy savings with a 1% minimum annual floor for modeling is an aggressive, but reasonable path forward with regard to the long-term UEE forecast use in resource planning. Approval of the proposed revisions in the Companies' DSM/EE Cost Recovery Mechanism, however, is critical to the Companies' efforts.

As shown in Figures 2 and 3 below, the Companies' respective UEE forecasts reach 1.5% of eligible load in the first 5 to 10 years before returning to the 1% floor level. While the base assumption is a 1% floor for UEE savings, as shown in the figures below, the Companies are anticipating UEE savings in the near-term above the 1.5% level due to IRA rebates that then taper off over time as those rebates end.

Figure 2 – DEC Annual UEE Savings Base Forecast

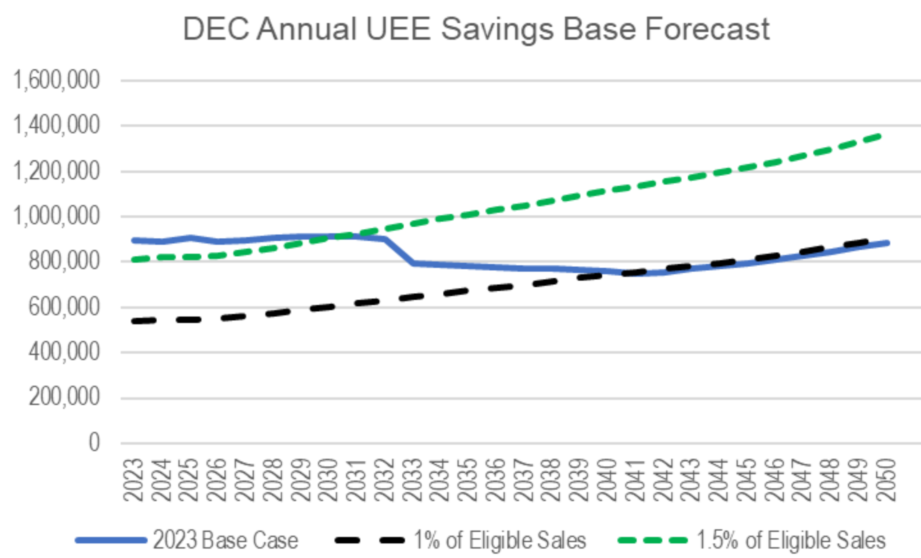
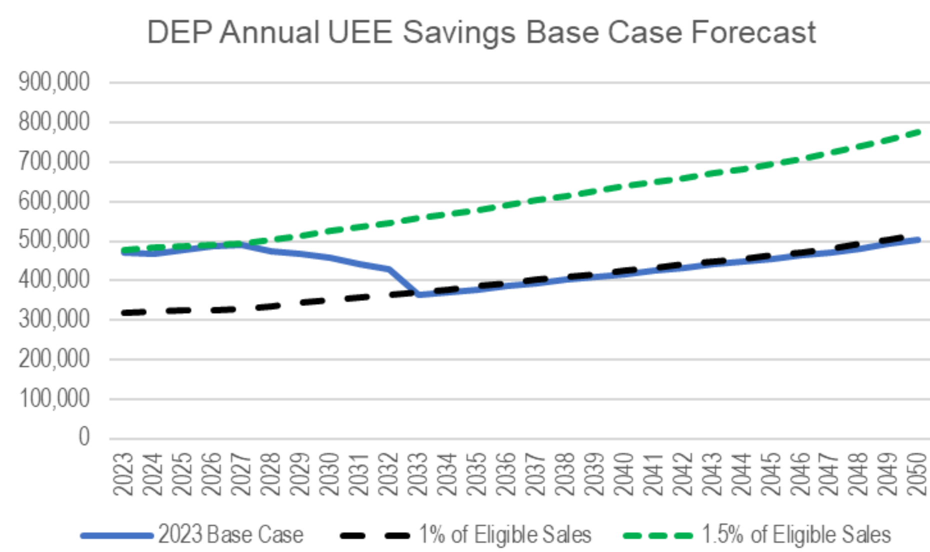


Figure 3 – DEP Annual UEE Savings Base Forecast



For the reasons discussed in this testimony, however, challenges in achieving the 1% annual EE savings over the planning period remain. In addition to the updated 2023 MPS and the new load I have discussed, several market conditions, outlined in detail Appendix H, continue to act as significant barriers to attracting the customer participation necessary to reach these aggressive levels of savings. The Companies continue to work to overcome these barriers and to engage, incent and encourage both residential and non-residential customers to participate in their DSM/EE programs. The Companies are continually working with the Collaborative to make their DSM/EE programs more attractive to both residential and non-residential customers. Moreover, the Companies are actively developing strategies to become the "go to" place for customers to learn about the IRA rebates available, how those rebates may complement the Companies' incentives, and how the Companies might assist in applying for them. Ultimately, however, the effectiveness of their EE and DSM programs relies on customer decisions and behavior that the Companies do not control.

D. Demand Response

Q. HAVE THE COMPANIES' FORECASTS FOR THE AMOUNT OF DEMAND RESPONSE CAPABILITY INCLUDED IN THEIR RESPECTIVE RESOURCE PLANS CHANGED?

A. No. While the annual forecasts of winter demand response capability have shifted by year, the total amount of forecasted winter demand response capability included in the Plan by 2030 remains unchanged compared to prior resource plans. The winter demand response capability for the Companies is forecasted to increase by almost 40% from the June 2023 levels by the end of 2030 and reach 1050 MW of winter capability in 2030.

Q. PLEASE HIGHLIGHT SOME OF THE INITIATIVES THE COMPANIES ARE UNDERTAKING TO ENSURE THAT THEY MEET THE AGGRESSIVE INCREASE IN WINTER DEMAND RESPONSE CAPABILITY BY 2030.

A. As described in Appendix H, the Companies are focused on growing winter peak capability through a robust number of initiatives and programs. I will highlight a few of those programs here:

- **Residential Heat Strip Direct Load Control Switch Program.**

The Companies continue to seek more demand response capability associated with customers utilizing electric heat strips for both primary and auxiliary heat. DEC received NCUC approval in Q4 2022 for this program. Due to historically being winter planning, the western region of the DEP NC service territory has had a heat strip control program for a decade. The Companies are working to expand this offering across the remainder of—DEP's service territory.

- **Water Heater program.**

DEP West continues to offer a load control program targeting electric water heaters. While this program historically has not been cost effective in the Companies' other North Carolina service territory, the Companies believe that recognition of increases in system benefits associated with capacity savings (currently an enabler the Companies propose for inclusion in the revised DSM/EE Cost Recovery Mechanism) could change this outcome in the future. The Companies are also investigating a low potential, lower-cost solution to leverage Wi-Fi connected water heaters, which manufacturers indicate are becoming more common. The program is not part of Plan modeling but could help achieve the 2030 targeted levels of winter demand response capability.

- **DEC Large Customer PowerShare Firm Load Reduction Option.**

This option is consistent with the NCUC's Carbon Plan Order in that it is intended to attract non-residential customers who otherwise would opt-out of the DSM/EE Rider.[10] After hearing from industrial customer groups during the Comprehensive Rate Design Study that the Companies should develop additional demand response options for customers and investigate a program offering similar to the one available in California, DEC has developed a new option for customers under the existing PowerShare program. Under this new offering, customers willing to commit to a specific quantity of hours to curtail load at the request of DEC can earn an additional incentive. Today, PowerShare is an emergency only program. However, this additional option, which DEC plans to file as a three-year pilot in late third quarter 2023, will be utilized more frequently to potentially avoid the need for CT starts and purchased power.

- **Behind the Meter Residential Storage Option.**

As discussed above, along with the Companies' proposed PowerPair Pilot filing in North Carolina, which is intended to incentivize residential customer adoption of solar plus storage, the Companies also filed for approval to add a storage related demand response offering to their respective existing residential demand response program tariffs.[11] This new storage option would be open to

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[10] *See* Carbon Plan Order at 133-34 (Ordering Paragraph No. 28).

[11] Proposed Modifications to Power Manager; Proposed Modifications to EnergyWise.

both PowerPair participants and other customers that have already installed eligible storage at their residences. Given the timing of this potential demand response capability addition, the Companies have not modeled it in the CPIRP, but would expect it to be included in the Companies' next CPIRP as more information is gathered about the program.

E. Voltage Optimization

Q. CAN YOU PLEASE DESCRIBE VOLTAGE OPTIMIZATION?

A. As described in more detail in Appendix H, voltage optimization is the coordinated control of substation and power line equipment to manage voltage and power factor on distribution circuits.

Q. PLEASE DESCRIBE THE IMPLEMENTATION STATUS OF THE VOLTAGE OPTIMIZATION SYSTEMS FOR THE COMPANIES THAT WERE FACTORED INTO THE FORECASTED IMPACTS.

A. DEP has leveraged voltage optimization for peak-shaving capability for a decade and has received the necessary regulatory approval to expand the capabilities of the existing DSDR equipment beyond peak shaving to support Conservation Voltage Reduction ("CVR"). DEC has proposed to implement voltage optimization in three phases and has been implementing the first phase of the required CVR upgrades that were approved in its Grid Improvement Plan. The other two phases of voltage optimization upgrades on distribution circuits were submitted for approval as part of its Multi-Year Rate Plan filing made in early 2023.[12]

Q. DOES THE CPIRP REFLECT THE IMPACTS OF CONTINUED INVESTMENT AND IMPLEMENTATION OF VOLTAGE OPTIMIZATION?

A. Yes. The Companies have appropriately reflected both the CVR-related MWH reductions associated with 90% of the hours of operation as well as the MW peak reduction associated with 10% of the hours of operation. A voltage reduction of 2% driven by CVR technology roughly equates to a 1.4% reduction in load for CVR-enabled circuits.

IV. RATE DESIGN

A. Rate Design Modernization

Q. WHAT FACTORS ARE DRIVING RATE DESIGN MODERNIZATION IN THE CAROLINAS?

A. Increasingly, customers are requesting more rate options and more control over energy costs, in part because adoption of distributed energy technology is reducing homogeneity amongst customers and creating a need for more sophisticated pricing approaches. The energy transition is creating supply-side and demand-side considerations that need to be considered when setting price structures to reflect new grid realities. The Companies' investments in metering

[12] *See* Duke Energy Carolinas, LLC's Application to Adjust Retail Base Rates and for Performance-Based Regulation, and Request for an Accounting Order, Docket No. E-7, Sub 1276, Exhibit A at 2 (Jan. 19, 2023).

and billing technologies are also significant enablers providing more complex or dynamic pricing options to customers.

Q. PLEASE PROVIDE AN OVERVIEW OF THE RATE DESIGN CHANGES THAT HAVE BEEN PROPOSED OVER THE PAST YEAR THAT SUPPORT THE RESOURCE PLANNING PROCESS.

A. In 2021, the NCUC ordered the Companies to conduct a year-long Comprehensive Rate Design Study to help guide future rate changes and/or new rates. The Companies engaged with numerous stakeholders and comprehensively addressed rate design questions that culminated in a Roadmap filing on March 31, 2022.[13] The Companies have both subsequently filed rate cases or other separate filings with material recommendations on rate design changes that flowed from the Roadmap. Such changes included, but are not limited to:

- New Time-of-Use and Demand charge structures that better align price signals with system costs and improve customers' ability to respond to price signals and control costs;
- Net Energy Metering for Rooftop Solar reform for both residential and non-residential applications;
- New rate options for Non-Residential Customers including High Load Factor and Hourly Pricing rates; and
- Rates supportive of customers adopting EVs, including residential,

[13] DEC & DEP's Rate Design Study Roadmap, Docket Nos. E-7, Sub 1214, E-2, Sub 1219 (Mar. 31, 2022).

fleet, and Direct Current fast charging.

Such rate design changes are intended to provide greater customer choice and, importantly, greater customer control over energy costs. Customers who can modify their consumption to align with the new price signals will not only realize bill savings but will create benefits to the grid that support low long-term costs for all customers.

Q. WERE THE PROPOSED RATE DESIGNS DEVELOPED WITH CUSTOMER AND STAKEHOLDER SUPPORT?

A. Yes. More than 50 organizations participated in numerous meetings and breakout sessions, all facilitated by a third-party administrator. The Companies filed quarterly reports with the NCUC, in addition to the final Roadmap, which reflected ideas provided and/or reviewed by the various participating entities.

Q. THE COMPANIES ARE ANTICIPATING CONTINUED GROWTH IN NET ENERGY METERING, AS MODELED IN THE PLAN. CAN YOU PLEASE DESCRIBE RECENTLY PROPOSED OR APPROVED CHANGES TO NET ENERGY METERING TARIFFS OR POLICIES THAT COULD INFLUENCE BEHIND THE METER GENERATION?

A. The Company worked collaboratively with customers and other stakeholders to develop and file important reforms for Net Energy Metering (also referred to herein as Rooftop Solar) for both residential and non-residential customers. Residential reforms recently approved by the NCUC included mandatory Time-of-Use ("TOU") participation, monthly netting, and particular pricing elements to address fixed cost recovery such as grid access fees and non-bypassable charges.[14] Non-residential changes recently approved for DEP and still pending before the NCUC for DEC as part of its recently filed rate case include mandatory TOU participation, monthly netting, elimination of standby charges for certain generation types, and an increase to the system size cap up to 5 MW. Altogether, the Companies' proposals provide durable and scalable programs that allow for expanded Rooftop Solar participation, both in terms of number of customers and system sizes, and that appropriately align the costs and benefits of solar adoption.

B. <u>Load Impacts from Rate Design Changes</u>

Q. HOW ARE THE BASE TARIFF IMPROVEMENTS EXPECTED TO RESULT IN MORE GRID BENEFICIAL CONSUMPTION PATTERNS FROM CUSTOMERS?

A. Generally speaking and responsive to the Carbon Plan Order, both the new and pending rate designs are superior to the prior designs in terms of effectively enabling beneficial customer response.[15] The Company anticipates that the 3-hour on-peak period will be both more manageable to avoid for customers with flexible loads and also more worth the effort. Importantly, shorter duration on-peak periods are not just easier to avoid, but also allow for greater spreads between pricing of on-peak and off-peak periods, increasing the economic incentive for changes in consumption behavior.

[14] Order Approving Revised Net Metering Tariffs, Docket No. E-100, Sub 180 (Mar. 23, 2023).

[15] *See* Carbon Plan Order at 134 (Ordering Paragraph No. 29).

Q. DO THE COMPANIES ANTICIPATE MORE TOU RATE ADOPTION FOR RESIDENTIAL CUSTOMERS IN THE FUTURE?

A. Yes. The Companies proposed pricing in the recent rate cases that will encourage migration over time. Additionally, the Companies are now providing a Rate Comparison Tool to enable easy comparisons of available rate options for interested customers.

Q. DOES AN INCREASE IN PARTICIPATION IN TOU RATES DELIVER THE CAPACITY BENEFITS DESCRIBED IN THE CPIRP?

A. TOU rate adoption is necessary, but not sufficient in isolation. Capacity benefits from these rate structures are realized only after customers modify consumption practices in response to price signals. Accordingly, customers will need to incorporate passive or active responses to reduce loads during times of grid constraints to yield capacity benefits. The Companies' new pricing designs are thus foundational for such benefits.

C. EV Programs and Pilots

Q. PLEASE DESCRIBE THE INCREASE TO THE FORECASTED EV ADOPTION INCLUDED IN THE COMPANIES' CAROLINAS RESOURCE PLAN.

A. The Companies develop its EV load forecast by using the Guidehouse Vehicle Analytics and Simulation Tool VAST. The pace of EV adoption across the Carolinas has grown rapidly and is forecasted to continue to quickly grow due to a number of tailwinds including encouraging state policy, federal incentives, such as the IRA, automaker commitments to increase EV sales, and more vehicles becoming available. These adoption trends have resulted in a higher forecast than what was forecasted in previous years. The Spring 2023 forecast estimates approximately 900,000 EVs on the road in the Carolinas by end of 2030 compared to previous forecast of approximately 570,000 EVs on the road by end of 2030.

Q. PLEASE DISCUSS HOW THE COMPANIES ARE USING GRID EDGE AND CUSTOMER PROGRAMS TO ADDRESS GROWING CUSTOMER ADOPTION OF EVs.

A. The Companies have been pursuing a three-pronged approach to accommodating the projected impacts of accelerated EV adoption.[16] First, the Companies have developed and continue to develop programs to ensure that EV charging infrastructure is made available to customers. Second, innovative programs and offerings will help manage EV loads' impact on the Companies' system peaks. Finally, the Companies are leveraging electrification and system planning experts to evaluate the Carolinas' operating regions to determine where strategic planning is needed to incorporate clusters of fleet operators without jeopardizing system reliability.

Q. PLEASE DESCRIBE THE COMPANIES' EFFORTS TO ADDRESS GROWING CUSTOMER NEEDS AROUND CHARGING INFRASTRUCTURE TO SUPPORT EV ADOPTION.

A. As discussed in more detail in Appendix H, the Companies have made a significant effort to address growing customer needs around EV charging. I

[16] *See* Carbon Plan Order at 134 (Ordering Paragraph No. 30).

discussed a few examples below.

- **Make Ready or “Charger Prep” Credit**

The Commission approved the Companies Make Ready or “Charger Prep” Credit Program on February 18, 2022.[17] The Make Ready Program is designed to simplify customer adoption of infrastructure to support EV adoption. The program provides funding and potentially qualified contractor referrals to install required equipment up to the EV charger, but not the charger itself.

- **Charger Solution**

Electric Vehicle Supply Equipment (“EVSE”) program (marketed under the name Charger Solution), which the NCUC approved by order issued August 8, 2023,[18] is another foundational program that will assist customers in adopting EVs and help facilitate adoption of capable of supporting more “whole house” managed charging offerings in the future, better enabling the grid for the electrification of transportation. The Charger Solution program provides customers—residential and non-residential—with the ability to select a charger to be installed for a flat amount each month, including maintenance. This program also enables grid benefits by ensuring that the charging infrastructure is appropriately compatible with potential managed charging opportunities and installed in a safe and reliable manner to support the grid.

[17] Order Approving Make Ready Credit Programs with Conditions, Docket Nos. E-2, Sub 1197 and E-7, Sub 1195 (Feb. 18, 2022).

[18] Order Approving Customer Operated Electric Vehicle Supply Equipment Tariffs with Conditions, Docket No. E-7, Sub 1195 (Aug. 8, 2023).

Q. PLEASE DESCRIBE THE COMPANIES' EFFORTS TO ENSURE THAT THE EXPANDING EV LOADS WILL OPERATE IN A MANNER THAT WILL LIMIT IMPACTS TO SYSTEM PEAKS.

As discussed in more detail in Appendix H, the Companies continue to actively develop a portfolio of customer offerings that include both passive offerings designed to send price signals to customers to discourage charging during peak demand periods and active control programs that allow the Companies to directly manage charging activities. I highlight a few examples below.

- Residential Off-Peak Credit

The Companies have been piloting the "Residential EV Charging Program", which provides a monthly credit to residential customers who avoid charging their EVs during on-peak times, in South Carolina. The Companies believe expanded and improved programs — even without specific technology requirements — can effectively shift significant EV charging load, especially in the summer peak. They intend to file a similar program in North Carolina in the fourth quarter of 2023.

- **Time of Use and Critical Peak Pricing**

Whole home TOU rates offer another option to allow customers to passively and automatically manage charging activities in grid beneficial ways, enabled by the modernized pricing periods being refreshed across the Companies' service territories. These updates will provide meaningful and beneficial price signals to encourage off-peak charging behaviors for EV owners, including EV fleets. The Companies anticipate EV owners will take advantage of the new price signals by shifting loads to reduce charging costs, while simultaneously benefitting all customers by avoiding adding to demands during capacity constrained times.

- **Managed Charging/Subscription Rate Pilot**

The Companies' Managed Charging/Subscription Rate Pilot was developed in partnership with a number of the EV manufacturers.[19] Available to 200 customers across the entire North Carolina service territory, it is intended to demonstrate how managed charging can create benefits for both EV owners and non-EV owners by ensuring charging occurs during non-peak periods. Enrollment for the pilot is intended to begin September 2023, with a subsequent launch in November 2023. The pilot will operate for 12 months with findings informing future managed charging program options.

- **Vehicle-to-Grid Pilot ("V2G")**

The Companies are going a step beyond simply managing when EV charging occurs with the V2G Pilot Program, approved for DEC in North Carolina in April 2023.[20] This pilot is an innovative effort designed to test the demand response capabilities of V2G dispatch from capable electric vehicles. The program was developed to leverage the new Ford Lightning and potentially other V2G-capable EVs and will enroll up to 100 residential customers. The Companies hope to test the demand response capabilities to not only ensure that

[19] Application for Approval of EV Managed Charging Pilots, Docket Nos. E-7, Sub 1266, E-2 Sub 1291 (July 7, 2023).

[20] DEC Application for Approval of Electric Vehicle-to-Grid Pilot Program, Docket No. E-7, Sub 1275 (Aug. 16, 2022).

the EV charging does not increase peak but also to leverage the EV battery to reduce system peaks.

Q. PLEASE DESCRIBE HOW THE COMPANIES ARE LEVERAGING ELECTRIFICATION AND SYSTEM PLANNING EXPERTS TO EVALUATE AND ACCOMMODATE POTENTIAL FLEET CLUSTERS WHILE LIMITING IMPACTS TO SYSTEM RELIABILITY.

A. Expected electrification of vehicle fleets will expand the need for substation and feeder capacity, which presents potential challenges for customers and utility operators as such expansions may occur in a concentrated, localized manner in warehousing districts or in proximity to air transportation. Such demand clustering, and the associated risks, however, may be mitigated through strategic planning, funding, and early execution. Put simply, a proactive approach.

The Companies are actively performing outreach with national accounts and entities that are not historically electric intensive but hold higher potential for commercial fleet electrification. The Companies' approach to facilitating EV adoption for this customer segment will have significant impact on the amount of grid investment ultimately required.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ON THE COMPANIES' PROACTIVE APPROACH TO MANAGING FLEET CLUSTERS.

A. The Companies' approach first identifies areas in which fleets operate now and determines if those have public electrification goals or significant potential economic benefit through electrification.

Next, sites are assigned a probability of electrification and coupled with data on anticipated per vehicle charging loads. Thus, for any given cluster area, blended adoption estimates can be established inclusive of grid impact. Clusters are then targeted based on their potential to outpace capacity to serve if adoption rates accelerate as anticipated.

The Companies plan to adjust and refine this approach while also building electric fleet analytical tools that integrate well with the time-tested system planning approaches already in use. Importantly, thoughtful approaches to such clustered fleet electrification may support continued economic growth in the Carolinas by reducing barriers to fleet electrification.

D. Behind the Meter Storage (Rooftop Solar)

Q. ARE BEHIND THE METER STORAGE RESOURCES GROWING IN THE COMPANIES' CAROLINAS SERVICE TERRITORIES?

A. Yes. As described in Appendix H, Rooftop Solar is expanding across the Carolinas and, increasingly, customers are pursuing pairing storage resources with solar. While fewer than 1% of Rooftop Solar customers in 2019 installed storage, in 2022 approximately 10% of solar adopters were adding storage to their systems. In part driven by beneficial tax credits, such assets can provide increased reliability to Rooftop Solar adopters. Accordingly, the Companies are continuing to explore ways to create grid benefits for the larger system as such investments are made by individual customers. One approach is the recently filed PowerPair program, currently pending before the NCUC.

Q. PLEASE DESCRIBE THE COMPANIES' POWERPAIR PILOT'S POTENTIAL BENEFITS.

A. The Companies have filed for approval a pilot program that provides an incentive for customers to install storage and either use the storage to optimize consumption against TOU price signals or grant the utility certain abilities to control battery operations for grid beneficial purposes. The Companies can learn from such pilots so as to better accommodate operations of customer owned batteries as well as encourage beneficial charging practices.

V. CUSTOMER CLEAN ENERGY PROGRAMS

Q. HOW ARE THE COMPANIES WORKING TO IMPROVE CUSTOMER ACCESS TO RENEWABLE ENERGY THROUGH PROGRAMS OTHER THAN NET-ENERGY-METERING AND EV INITIATIVES?

A. In 2022, the Companies began extensive stakeholder engagement to develop the next iteration of Clean Energy Programs. These new programs are critical to both existing and potential new customers as they are looking for ways to meet their sustainability goals.

Q. PLEASE DESCRIBE THE CLEAN ENERGY PROGRAMS THE COMPANIES HAVE FILED SO FAR.

A. The Companies have filed two program options in both North and South Carolina:

- **GSA Choice (“GSAC”)**[21]

Next iteration of the GSA program, providing large business customers the opportunity to partner with a renewable generating facility off-site. GSAC benefits the many customers who do not have the ability or the space to develop a solar facility on their property. Key enhancements include: allowing for customers to contract for up to 100% energy matching, the flexibility to partner directly with Duke Energy on a long-term contract for either Duke Energy- or third-party-owned generation, and an optional grid-tied energy storage feature to facilitate the 24/7 clean energy desired by some customers.

- **Clean Energy Impact (“CEI”)**[22]

Provides a simple, low-cost option with no long-term commitment for customers to purchase locally sourced Clean Energy Environmental Attributes (“CEEAs,” which are North Carolina Renewable Energy Certificates and carbon free reduction attributes) from local sources. Revenue received from these purchases will benefit all retail customers. This will be a new alternative to the current Renewable Advantage program in North Carolina, providing more locally-sourced CEEAs.

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[21] DEC and DEP Joint Petition for Approval of Green Source Advantage Choice Program, Docket Nos. E-7, Sub 1289, E-2, Sub 1314 (Jan. 27, 2023); Renewable Choice, Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to Establish Customer Renewable Programs, Docket No. 2022-326-E (Oct. 5, 2022); and GSA Modifications; Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to Establish Green Source Advantage Programs and Riders GSA, Docket No. 2018-320-E (Oct. 10, 2018).

[22] DEC and DEP Joint Petition for Approval of Clean Energy Impact Program, Docket Nos. E-7, Sub 1288, E-2, Sub 1315 (Jan. 27, 2023); Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to Establish Customer Renewable Programs, Docket No. 2022-326-E (Oct. 5, 2022).

Q. ARE THERE ADDITIONAL PROGRAM CONCEPTS DISCUSSED WITH STAKEHOLDERS THAT THE COMPANIES INTEND TO FILE?

A. Yes. The Companies are still developing a program called Clean Energy Connection. This program is a community solar program where the Companies own the generating facility and customers of all classes can subscribe to benefit from the carbon-free, renewable energy.

Q. HAVE THE COMPANIES IMPLEMENTED A RAPID PROTOTYPING PROCESS FOR NON-EE/DSM PROGRAMS?

A. Yes. After the NCUC's Carbon Plan Order, the Companies initiated a Rapid Prototyping stakeholder process.[23] They have not yet implemented or filed a proposal to establish a rapid prototyping process; however, significant progress has occurred. The Companies have been engaging with stakeholders since February 2023, pursuant to the NCUC's Carbon Plan Order, to develop a process that accelerates the ability to leverage opportunities that new energy consuming and storing technologies present to Grid Edge and Customer Programs. The Companies and a diverse group of stakeholders have collaborated to review rapid prototyping processes in other jurisdictions and to discuss guiding principles that could potentially be applicable rapid prototyping guidelines for the Companies to propose. The Companies will continue to engage with stakeholders to gain consensus on which types of prototyping would qualify for expedited regulatory approval and the role of stakeholders in

[23] *See* Carbon Plan Order at 134 (Ordering Paragraph No. 32).

prototyping development. The Companies currently envision the rapid prototyping process applying to smaller, innovative pilot customer programs and rate designs. A rapid prototyping process proposal is anticipated to be filed in the third quarter of 2023.

VI. CONCLUSION

Q. MESSRS. DUFF AND BYRD, DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Duke Energy North Carolina Energy Efficiency and Demand-side Management Market Potential Report

Date: July 2023

Contents

1. Executive Summary

In fall of 2021, Duke Energy retained Resource Innovations, formerly Nexant Inc., to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand-side management (DSM) programs in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) service territories. This report describes the potential for EE and DSM savings among these two service territories in North Carolina. The main objectives of the study include:

- Estimating EE and DSM potential over the short term (five years), medium term (ten years), and long term (twenty-five years) planning horizons
- Exploring the sensitivity of savings estimates to changes in incentive rates and avoided energy costs
- Developing customer participation estimates that are independent of historical Duke Energy program trends
- Assessing the potential impact of the 2022 Inflation Reduction Act on EE/DSM savings potential
- Engaging the Carolinas EE/DSM Collaborative members and offering opportunities for feedback and contribution to the market potential study (MPS)
- Providing data to Duke Energy for integrated resource planning

Technical potential indicates the theoretical upper limit on savings from EE. We estimate cumulative technical potential as a share of all 2047 electricity sales to be 21% in DEC and DEP (regardless of customer EE/DSM opt-out status). Technical potential ignores measure costs to focus on energy savings wherever technically feasible. Cumulative economic potential is 18% of all sales, regardless of EE/DSM program eligibility. This estimate is based on using the utility cost test (UCT) to determine if a measure is cost-effective. The test compares the costs and benefits of offering a measure to customers through a utility-sponsored EE or DSM program.

The UCT costs are for utility incentives and program administration, and UCT benefits stem from avoiding the energy, capacity, transmission, and distribution (T&D) costs of the electricity saved by the program measure. Economic potential with a UCT screening criterion does not examine customer benefits and costs; rather, it simply assumes all customers adopt a measure that is cost-effective under the UCT screening directive. As constructed, this economic potential estimate using a UCT screening indicates how utility program costs and benefits affect measures' potential savings if all customers are assumed to adopt measures that are cost-effective for the utility to offer.

For customers eligibility to participate in EE/DSM programs ("opt-in" customers) Achievable Market Potential (AMP) represents expected customer adoption for each AMP scenario. Using the set of cost-effective measures from the UCT Economic Potential, Resource Innovations applied customer payback acceptance curves to calculate a measure's long-run market share relative to competing EE measures, including baseline technologies (e.g., current codes and standards). With the data available for this MPS, payback acceptance is the most feasible approach for estimating customers' willingness to invest in EE/DSM equipment and retrofit measures. As the payback acceptance approach considers only simple payback and the presence of utility incentives from the economic potential scenario, the achievable potential scenario implicitly assumes programs continually identify and successfully reduce barriers to customer participation. Duke Energy has a demonstrated history of applying best practices and concepts from the EE and DSM program lifecycle to accomplish this end by continually engaging in the cycle of program planning, implementation, evaluation, and adaptation.

We present results for three primary scenarios:

- **Base** – reflects current Duke Energy programs and program costs, incentive rates, and utility avoided cost benefits generated by the program
- **High Incentive** – doubles current incentive rates with a cap at 100% of the measure incremental cost; applies utility avoided cost benefits from the base scenario
- **High Avoided Costs** – increases utility avoided cost benefits by 50%, uses base scenario incentive rates

1.1.1. Energy Efficiency Potential

The estimated technical and economic potential scenarios for DEC are summarized in Table 1-1, which lists cumulative energy and demand savings for each type of potential. Savings percentages are presented as a share of end year sales over 25 years. These projected sales values were adjusted to remove opt-out customers.

Table 1-1: DEC Energy Efficiency Technical and Economic Potential (2023 – 2047)

Scenario	Energy (GWh)	% of End Year Sales	Demand (MW)	
			Summer	Winter
Technical Potential	14,448	21%	3,069	2,179
Economic Potential	12,129	18%	2,436	1,980

Table 1-2 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) DEC portfolio EE achievable market potential for the base, high incentive, and high avoided cost scenarios. AMP estimates adjust the customer base to remove customers that have opted-out of EE and DSM; these impacts are presented over each stated time horizon (5 years, 10 years, or 25 years).

Table 1-2: DEC Energy Efficiency Achievable Market Potential

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (kWh)	579,363	615,519	525,878
High Incentive	Annual Incremental Energy (kWh)	686,428	724,304	586,078
High Avoided Cost	Annual Incremental Energy (kWh)	588,942	624,389	527,666
Base	Annual Incremental Summer Peak Demand (kW)	122	129	111
High Incentive	Annual Incremental Summer Peak Demand (kW)	147	154	125
High Avoided Cost	Annual Incremental Summer Peak Demand (kW)	125	132	111
Base	Annual Incremental Winter Peak Demand (kW)	102	109	95
High Incentive	Annual Incremental Winter Peak Demand (kW)	122	129	107
High Avoided Cost	Annual Incremental Winter Peak Demand (kW)	103	110	96
Base	Cumulative Energy (kWh)	1,588,163	2,846,544	2,998,660
High Incentive	Cumulative Energy (kWh)	2,057,621	3,833,315	4,205,006
High Avoided Cost	Cumulative Energy (kWh)	1,620,726	2,881,450	3,007,027
Base	Cumulative Summer Peak Demand (kW)	325	574	585
High Incentive	Cumulative Summer Peak Demand (kW)	432	798	860
High Avoided Cost	Cumulative Summer Peak Demand (kW)	334	583	587
Base	Cumulative Winter Peak Demand (kW)	255	460	489
High Incentive	Cumulative Winter Peak Demand (kW)	339	644	729
High Avoided Cost	Cumulative Winter Peak Demand (kW)	257	462	489

Technical and economic potential for DEP are presented in Table 1-3. As above, cumulative energy impacts are presented as a share of end year sales for 2027, 2032, and 2047. End year sales for each period include all customers, regardless of opt-out status for the technical and economic potential scenarios.

Table 1-3: DEP Energy Efficiency Technical and Economic Potential (2023 – 2047)

Scenario	Energy (GWh)	% of End Year Sales	Demand (MW)	
			Summer	Winter
Technical Potential	8,934	21%	1,898	1,554
Economic Potential	7,396	18%	1,483	1,427

Table 1-4 presents DEP achievable market potential over the study time horizon. The table also presents demand savings and average annual percentage of base sales; base sales are adjusted to remove opt-out customers as they are not eligible for EE/DSM.

Table 1-4: DEP Energy Efficiency Achievable Market Potential

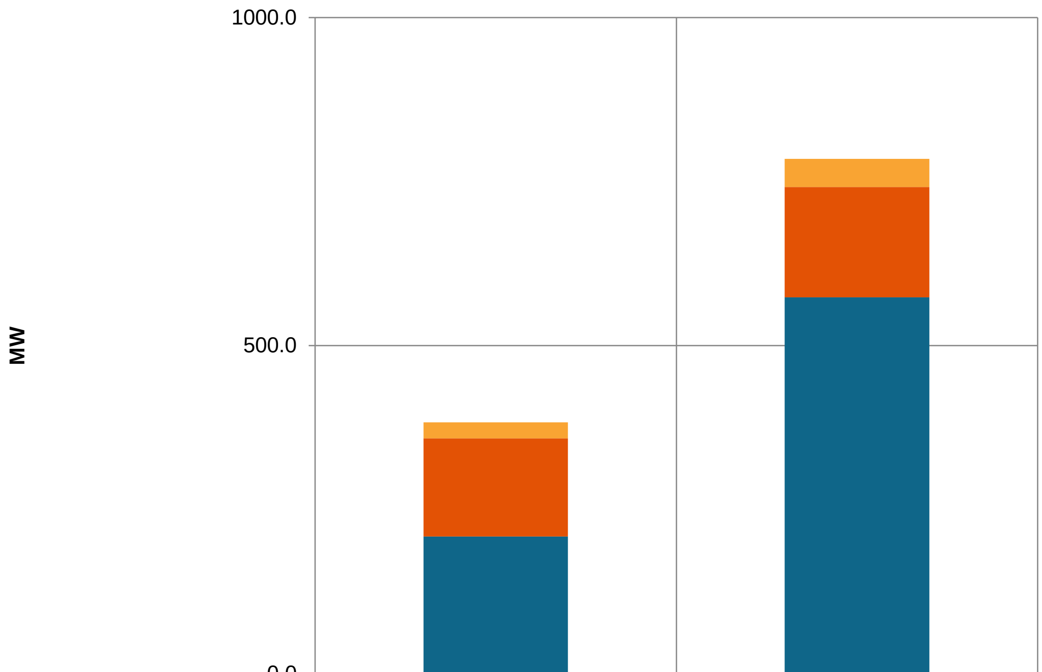
Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (kWh)	320,986	332,697	303,876
High Incentive	Annual Incremental Energy (kWh)	370,167	381,699	337,883
High Avoided Cost	Annual Incremental Energy (kWh)	330,030	340,909	305,939
Base	Annual Incremental Summer Peak Demand (kW)	66	69	63
High Incentive	Annual Incremental Summer Peak Demand (kW)	77	80	71
High Avoided Cost	Annual Incremental Summer Peak Demand (kW)	69	71	64
Base	Annual Incremental Winter Peak Demand (kW)	67	69	64
High Incentive	Annual Incremental Winter Peak Demand (kW)	81	83	73
High Avoided Cost	Annual Incremental Winter Peak Demand (kW)	67	70	64
Base	Cumulative Energy (kWh)	911,981	1,665,073	1,891,024
High Incentive	Cumulative Energy (kWh)	1,119,134	2,131,687	2,561,562
High Avoided Cost	Cumulative Energy (kWh)	946,170	1,705,346	1,906,500
Base	Cumulative Summer Peak Demand (kW)	183	335	380
High Incentive	Cumulative Summer Peak Demand (kW)	228	439	532
High Avoided Cost	Cumulative Summer Peak Demand (kW)	192	346	383
Base	Cumulative Winter Peak Demand (kW)	175	326	380
High Incentive	Cumulative Winter Peak Demand (kW)	235	457	565
High Avoided Cost	Cumulative Winter Peak Demand (kW)	178	329	382

1.1.2. Demand-side Management Potential

DSM opportunities were analyzed for North Carolina service territories to determine the amount of summer and winter peak capacity that could be reduced through DSM initiatives from a technical, economic, and achievable potential perspective. While technical and economic potential are theoretical upper limits, participation rates are calculated as a function of the incentives offered to each customer group for utility-enabled DSM. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DSM potential from that segment should be included in the achievable potential.

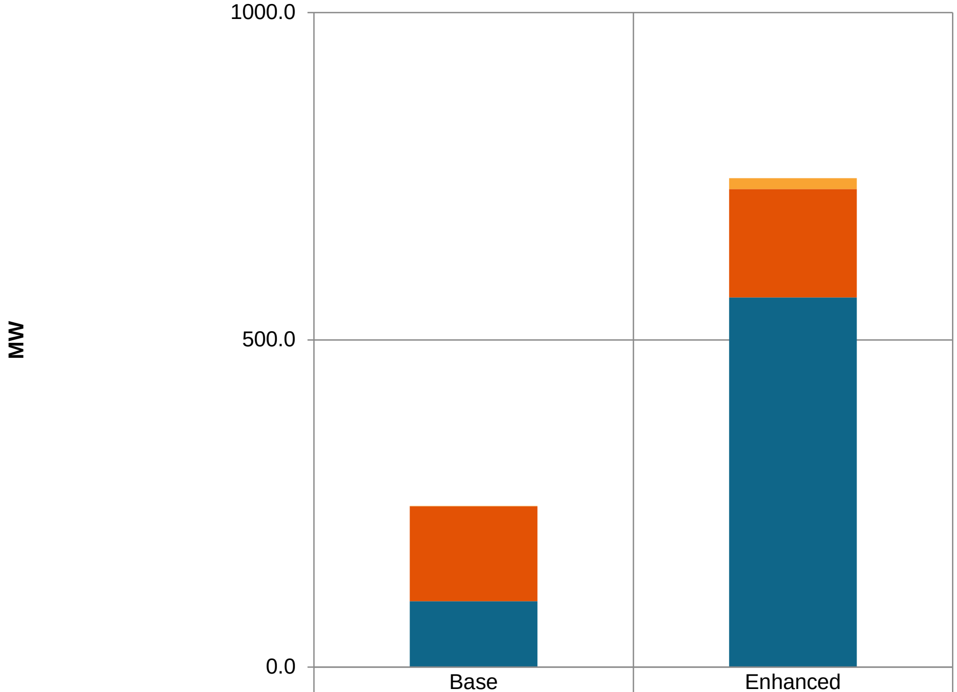
Figure 1-1 and Figure 1-2 summarize the summer peak and winter peak DSM potential estimated for DEC under two achievable scenarios analyzed in the study: a base and enhanced scenario. These scenarios differ in terms of incentive amounts offered, consistent with the higher incentive scenario analysis performed for EE (the avoided cost sensitivity scenario applies only to avoided energy costs). These results represent incremental DSM potential beyond current Duke Energy program enrollments.

Figure 1-1 DEC DSM Summer Peak Capacity Achievable Potential



	Base	Enhanced
Large C&I	24.1	43.1
Small and Medium Business	149.7	168.0
Residential	209.2	573.6

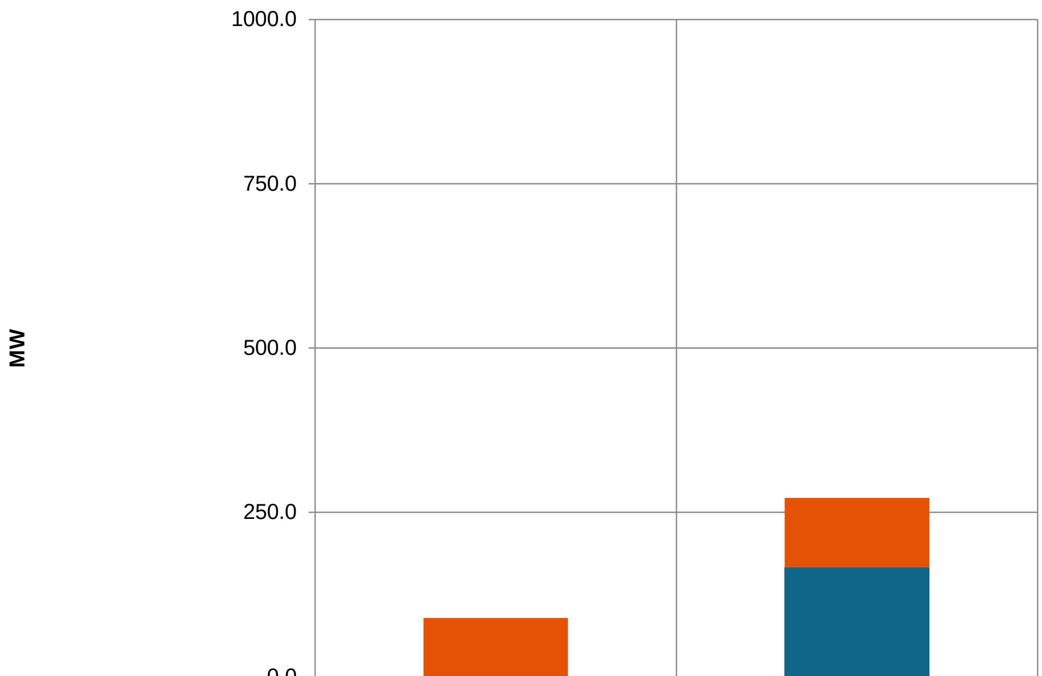
Figure 1-2 DEC DSM Winter Peak Capacity Achievable Potential



	Base	Enhanced
Large C&I	0.1	16.4
Small and Medium Business	145.1	165.6
Residential	100.5	564.9

Figure 1-3 and Figure 1-4 summarize the summer peak and winter peak DSM potential estimated for DEP under two achievable scenarios that affect DSM results.

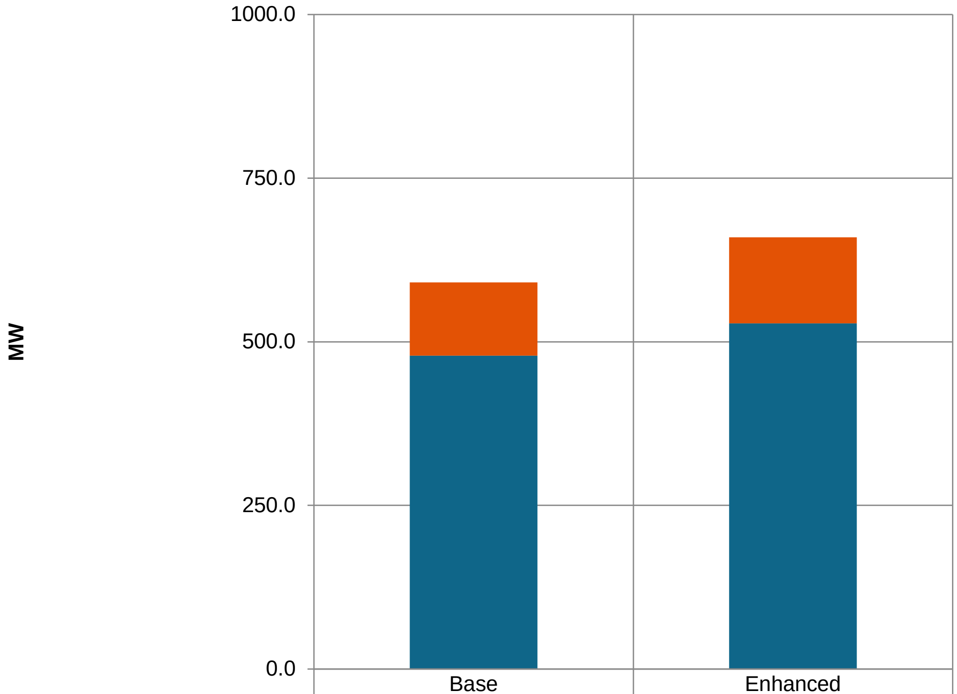
Figure 1-3 DEP DSM Summer Peak Capacity Achievable Potential[1]



	Base	Enhanced
Large C&I	0.0	0.0
Small and Medium Business	89.3	105.5
Residential	0.0	166.3

[1] Results are incremental to current DSM capacity provided by EnergyWise Business and CIG DRA programs

Figure 1-4: DEP DSM Winter Peak Capacity Achievable Potential



	Base	Enhanced
Large C&I	0.0	0.0
Small and Medium Business	111.5	131.2
Residential	479.1	528.1

2. Introduction

In fall of 2021, Duke Energy retained Resource Innovations, formerly Nexant Inc., to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand-side management (DSM) programs in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) service territories. This report describes the potential for EE and DSM savings among these two service territories in North Carolina.

2.1. Objectives and Deliverables

The main objectives of the study include:

- Estimating EE and DSM potential over the short term (five years), medium term (ten years), and long term (twenty-five years) planning horizons
- Exploring the sensitivity of savings estimates to changes in incentive rates and avoided energy costs
- Developing customer participation estimates that are independent of historical Duke Energy program trends
- Assessing the potential impact of the 2022 Inflation Reduction Act on EE/DSM savings potential
- Engaging the Carolinas EE/DSM Collaborative members and offering opportunities for feedback and contribution to the market potential study (MPS)
- Providing data to Duke Energy for integrated resource planning

RI developed the following deliverables for the MPS:

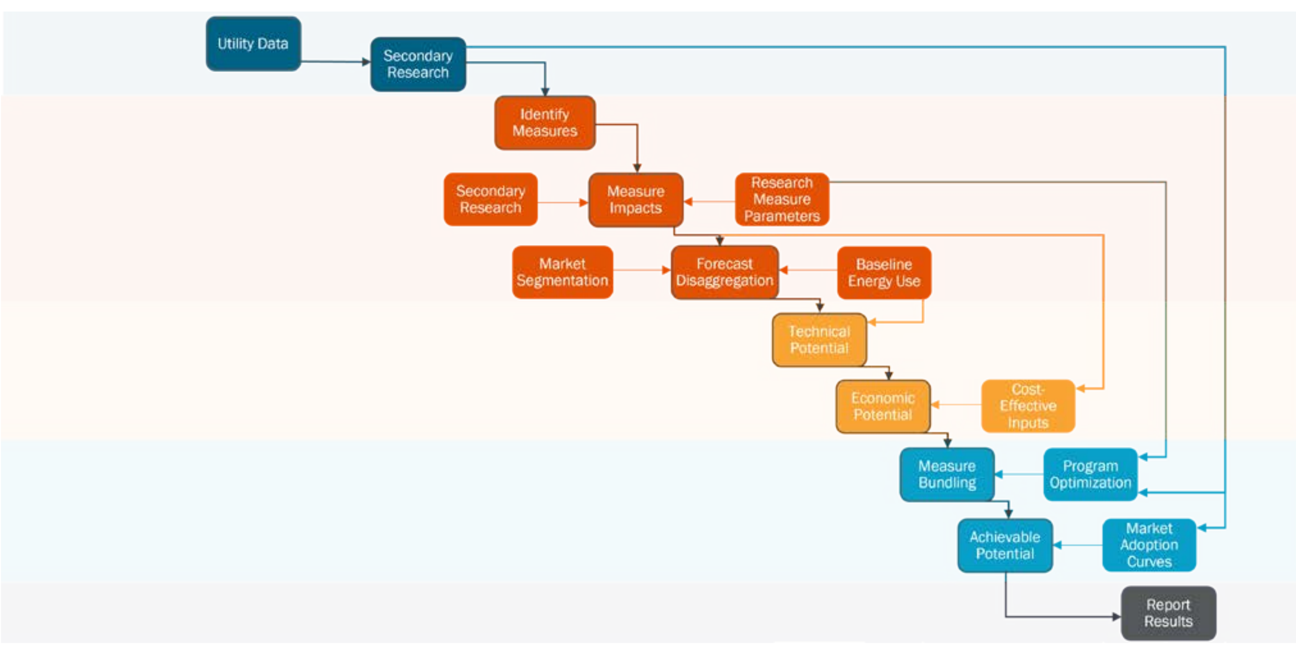
- Measure list and supporting memorandum describing the measure research process
- An MPS work plan and emerging technology review
- Periodic presentations to Duke Energy and Carolinas EE/DSM Collaborative
- Duke Energy Program Review Volume I: Market Barriers and Program Strategies; Duke Energy Program Review Volume II: Review of Duke Energy EM&V and Duke Energy Program Strategies Targeting Market Barriers
- Background and discussion/workshop with Carolinas EE/DSM Collaborative and Program Feedback Template
- Responses to Carolinas EE/DSM Collaborative members' feedback on EE measure impacts
- Composite of program analysis, stakeholder engagement, and outcomes
- Interim, draft results of technical and economic potential
- Presentations to Duke Energy and stakeholders to solicit feedback on proposed approach for estimating the impacts of the 2022 Inflation Reduction Act
- Achievable potential estimates describing three APS scenarios: base, high incentive, and high avoided costs
- Achievable potential estimates with and without opt-in customers
- Achievable Potential with estimated impacts of the 2022 Inflation Reduction Act
- This report and summary of all project activities

2.2. Study Approach

Energy efficiency and market potential studies describe each type of energy efficiency potential: technical, economic, and achievable. A market potential study is an assessment of current market conditions and trends, as observed with available primary and secondary data. All components of the study, such as baseline energy consumption, expected utility sales forecasts, and available EE and DSM measures, among others, are determined on the basis of available data. A market potential study is therefore a discrete estimate of EE and DSM potential based on current market conditions and savings opportunities. An MPS does not contemplate potential changes in utility rates, changes in technology costs, nor changes in underlying economic conditions that provide a context for current consumption trends. This study considers existing technology and market trends as observed with currently available data and does not speculate on the potential impact of unknown, emerging technologies that are not yet market ready.

Resource Innovations developed estimates with models, tools, and techniques developed over dozens of client engagements for EE and DSM resource planning over the past two decades. We examined multiple scenarios by changing inputs related to program incentives, utility avoided cost benefits, and eligible customers. Resource Innovations used primary data provided by Duke Energy and secondary data sources to decompose DEC and DEP sales forecasts into customer-class and end use components. Resource Innovations characterized measures for all electric end uses, accounting for end use saturation, fuel shares, technical feasibility, current efficiency levels, and costs. As illustrated in Figure 2-1, we used these results to assess the savings that could be captured by Duke Energy customers with the full range of commercially available energy efficiency measures and practices. We estimated EE and DSM savings for each customer class, market segment, and electric end use by applying measure impacts to the service territory over time.

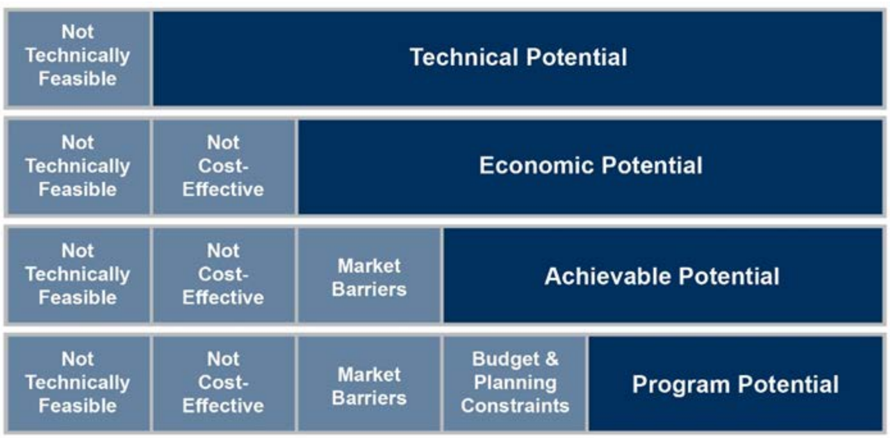
Figure 2-1: Market Potential Study Flow Chart



We aggregated measure impacts for the technical, economic, and achievable scenarios by sorting and ranking measures according to scenario criteria and modeled the application of measures to replace equipment failures or to retrofit existing buildings. Following regulatory and stakeholder direction, we estimated economic potential by applying the utility cost test (UCT) to weigh EE and DSM costs against their estimated benefits, the latter provided to us by Duke Energy.

The savings potential for EE and DSM in Duke Energy's North Carolina territory is characterized by levels of opportunity. The ceiling or theoretical maximum savings is based on commercialized technologies and behavioral measures, whereas the realistic savings that may be achieved through DSM programs reflect real world market constraints such as utility budgets, customer perspectives and energy efficiency policy. This analysis defines these levels of energy efficiency potential according to the Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE) as illustrated in Figure 2-2.

Figure 2-2: Energy Efficiency Potential



EPA – National Guide for Resource Planning

Technical potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. economic potential is the amount of energy saved by applying efficiency measures that pass a cost-effectiveness test. The utility cost test (UCT) is used in this study, in keeping with jurisdictional practice. Achievable market potential is the energy savings that can be achieved in a market with cost-effective, utility-sponsored programs; achievable market potential is primarily driven by the influence of incentive levels on customer adoption rates and addresses market barriers associated with customer preferences and opportunity costs. Our analysis assumed Duke Energy will continue to adaptively manage programs, following the EE/DSM program life cycle: market assessment, program design, implementation, evaluation, and adaptation.

RI explored technical, economic, and achievable market program potential over a 25-year period from January 2023 to December 2047. The quantification of these three levels of energy efficiency potential reflects assumptions developed from feedback by the EE and DSM Collaborative, Duke

Energy, and regulators. Savings opportunity follows the path from a theoretical maximum to realistic savings potential in a market with utility-sponsored programs.

In collaboration with the North Carolina EE and DSM Stakeholder Collaborative we reviewed, compiled, and shared extensive documentation and summary of Duke Energy's historic and ongoing programmatic efforts. We also provided background information on market barriers and program strategies for overcoming them, a result of research compiled by experienced RI program delivery personnel. RI provided a template for suggestions concerning alternative strategies for addressing market barriers, with a request to identify specific program elements that would likely be affected.

Discussions with the Carolinas EE/DSM led to a recommendation for modeling achievable potential in a manner independent of historic program participation. We followed this recommendation and created estimates of achievable potential that are based on customer payback acceptance curves; this approach describes customers' adoption decisions relative to the length of time required to recoup their investment in energy efficiency.

Owing to these MPS parameters and focus, we describe our estimates as expected EE and DSM potential in a market featuring utility-sponsored programs and incentives. The estimates assume adaptive program management is applied to successfully lower market and non-market barriers to customer adoption over time; the customer payback acceptance approach addresses only the barriers of investment costs and opportunity costs.

Naturally occurring conservation and efficiency is captured in this analysis by the Duke Energy electricity sales and load forecasts. We addressed changing energy codes and equipment standards by incorporating changes to codes and standards in the development of the base-case forecasts or with adjustment to measure savings that reflect changing baselines. The Duke Energy forecasts account for known or planned future federal code changes and existing market trends towards more efficient equipment. RI estimated savings potential based on a combination of market research, analysis, and a review of Duke Energy's existing programs, all in consideration of feedback from Duke Energy and the EE/DSM Collaborative. The programs that RI examined included both energy efficiency (EE) and demand-side management (DSM) programs; therefore, this report is organized to offer detail on both types of programs.

The remainder of the report provides describes each step in the potential analysis process, together with the results and analyses, according to the following sections:

- Market Characterization
- Measure List
- Technical Potential
- Economic Potential
- Achievable Market Potential

3. Market Characteristics

Market potential studies estimate savings potential relative to existing market conditions. This study used base year energy use and sales forecasts provided to us by Duke Energy. We used customer segmentation and secondary data to decompose the sales forecast into its end use components and to describe customer segments in the DEC and DEP North Carolina service territories. This section presents baseline market conditions, while the subsequent sections address measure opportunities and market potential scenarios.

3.1. Customer Segments

As electricity consumption patterns vary by customer type, RI segmented customers to better describe opportunities for energy efficiency or customers' ability to provide DSM grid services. Customer segmentation provides higher resolution estimates of cost-effective EE and DSM programs. Significant cost efficiency can be achieved through strategic EE and DSM program designs that recognize and address the similarities of EE and DSM potential that exists within each customer group.

RI segmented DEC and DEP customers by economic sector to describe how much of the Duke Energy sales, summer peak, and winter peak load forecasts are attributable to the residential, commercial, and industrial sectors. Customer segments within each economic sector are used to estimate how much electricity each customer type consumes annually and during system peaking conditions. End use disaggregation looks within a typical home or business in each segment to describe the typical equipment using electricity during periods of peak demand and estimate annual consumption within each end use for current consumption trends.

RI used Duke Energy customer data to identify customers that have opted out of EE or DSM, as such customers are not eligible to participate in Duke Energy programs. Table 3-1 lists study segments for each economic sector. We also segmented customers according to space heating fuel (electric vs. gas) and by annual consumption tertiles (that is, three groups of equal customer size). Segmentation allows for more accurate estimates of which customers exhibit consumption patterns that make them more or less cost effective to recruit for EE and DSM programs.

Table 3-1: MPS Customer Segments by Economic Sector

Residential	Commercial		Industrial	
Single Family	Assembly	Lodging/ Hospitality	Chemicals and plastics	Primary resource industries
Multifamily	College and University	Miscellaneous	Construction	Stone, clay, glass, and concrete
	Data Center	Offices	Electrical and electronic equipment	Textiles and leather
	Grocery	Restaurant	Lumber, furniture, pulp, and paper	Transportation equipment
	Healthcare	Retail	Metal products and machinery	Water and wastewater
	Hospitals	Schools K-12	Miscellaneous manufacturing	
	Institutional	Warehouse		

From an equipment and energy use perspective, each segment has variation within each building type or sub-sector. For example, the energy consuming equipment in a convenience store will vary significantly from the equipment found in a supermarket. To account for the resolution of available baseline consumption data, the selected end uses describe energy savings potential that are consistent with those typically studied in national or regional surveys. These end uses are listed in Table 3-2.

Table 3-2: Electricity End Uses by Economic Sector

Residential End Uses	Commercial End Uses	Industrial End Uses
Space heating	Space heating	Process heating
Space cooling	Space cooling	Process cooling
Domestic hot water	Domestic hot water	Compressed air
Ventilation and circulation	Ventilation and circulation	Motors, pumps
Lighting	Interior lighting	Motors, fans, blowers
Cooking	Exterior lighting	Process-specific
Refrigerators	Cooking	Lighting
Freezers	Refrigeration	HVAC
Clothes washers	Office equipment	Other
Clothes dryers	Miscellaneous	
Dishwashers		
Plug load		
Miscellaneous		

We targeted end uses with controllable load for residential customers and small/medium business (SMB) customers. Our estimates of winter DSM potential for SMB customers are based on Duke Energy's "bring your own kW" program model, which qualifies all load from these customers during peak hours as potential DSM capacity. For large commercial and industrial (large C&I) customers who would potentially reduce large amounts of electricity consumption for a limited time, all load during peak hours was included. For residential customers, AC/heating loads, as well as pool pumps and electric water heaters for certain program potential scenarios were studied. For SMB customers the analysis of summer DSM examined weather-responsive space cooling loads.

3.2. Forecast Disaggregation

We worked with Duke Energy to establish a common understanding of the assumptions and granularity in the baseline load and sales forecasts. We reviewed the following:

- How are Duke Energy's current program offerings reflected in the energy and demand forecast?
- What are the assumed weather conditions and hour(s) of the day when the system is projected to peak?
- How much of the load forecast is attributable to accounts that are not eligible for EE and DSM programs or have opted-out of the EE and DSM riders?
- How are projections of population increase, changes in appliance efficiency, and evolving distribution of end use load shares accounted for in the twenty-five-year peak demand forecast?

RI segmented the DEC and DEP electricity consumption forecasts by customer class and end use. The resulting baseline represents the North Carolina electricity market by describing how electricity was consumed within the service territory. RI developed these forecasts for the years 2023–2047 and based them on data provided by Duke Energy and supporting, secondary sources. The data addressed current baseline consumption, system load, and sales forecasts.

The baseline for DSM potential describes loads in the absence of existing, dispatchable DSM. This baseline was necessary to assess how DSM can assist in meeting specific planning and operational requirements. RI used Duke Energy's summer and winter peak demand forecast, which was developed for system planning purposes.

RI developed a list of electricity end uses by sector (Table 3-2) and examined EE and DSM measures that could potentially reduce baseline consumption for each end use. RI began with Duke Energy's estimates of average end use consumption for residential customers and shares of Duke Energy sales to non-residential customer segments. We combined these data with Duke Energy's 2019 residential appliance saturation surveys, data products from the Energy Information Agency (EIA), and estimates of manufacturing end use consumption from the Department of Energy (DOE).

3.3. Market Description

Customer segmentation addresses the diverse energy savings opportunities for Duke Energy's customer base. Duke Energy provided RI with data concerning the premises type and load characteristics for all customers. RI's approach to segmentation varied slightly for commercial and residential accounts, but the overall logic was consistent with the concept of expressing the accounts in terms that are relevant to EE and DSM opportunities. The following three sections describe the segmentation analysis and results for commercial and industrial C&I accounts (Section 3.3.1) and residential accounts (Section 3.3.2).

3.3.1. Commercial and Industrial Accounts

RI segmented C&I accounts according to two approaches: North American Industry Classification System (NAICS) codes and peak energy demand.

Duke Energy provided RI with customer data containing NAICS codes for individual accounts. RI further classified the customers in this group as *either* commercial or industrial. RI based this classification on the types of EE and DSM measures applicable to each segment, rather than on the annual energy consumption or maximum instantaneous demand from the segment as a whole. For example, agriculture and forestry EE measures are commonly considered industrial savings opportunities.

RI divided the non-residential customers eligible for DSM into the two customer classes: small and medium businesses (SMB) and large C&I using rate class and peak demand characteristics. These categories followed the definitions used by Duke Energy for load research samples. SMB customers are represented by commercial accounts included in Duke Energy's load research sample. Large C&I customers were designated by customers included in Duke Energy's census of AMI data for qualifying accounts.

RI segmented both the SMB and Large C&I customer classes with economic activity information for each account, which was provided by Duke Energy as part of the customer data. RI aggregated the SMB segments using data available in 2021, and the resulting customer counts are shown in Table 3-3 for SMB customers.

Table 3-3: Summary of SMB Segment

Segment	DEC Number of Accounts	DEP Number of Accounts
Assembly	31,063	10,281
College and University	1,619	534
Data Center	711	193
Grocery	3,590	1,691
Healthcare	8,268	3,861
Hospitals	795	469
Institutional	17,406	8,487
Lodging/Hospitality	3,818	5,287
Miscellaneous	7,904	989
Office	71,712	78,418
Restaurants	10,418	5,716
Retail	59,592	28,818
Schools K-12	6,021	2,166
Warehouse	6,229	5,891

Segment	DEC Number of Accounts	DEP Number of Accounts
Agriculture and Assembly	5,008	3,444
Chemicals and Plastics	989	246
Construction	10,931	3,164
Electrical and Electronic Equip.	1,760	25,717
Lumber/Furniture/Pulp/Paper	2,396	682
Metal Products and Machinery	2,606	385
Miscellaneous Manufacturing	3,306	691
Primary Resources Industries	2,937	1,656
Stone/Clay/Glass/Concrete	517	237
Textiles and Leather	979	248
Transportation Equipment	5,207	1,940
Water and Wastewater	7,122	5,072
Total (Unadjusted)	**272,904**	**196,283**
Total (Adjusted for DSM Participation)	**267,630**	**196,029**

Large C&I customers were defined for the DSM potential analysis on the basis of account size (demand). Duke Energy provided a census of AMI data to RI for estimating the DSM potential capacity available from these large accounts. Table 3-4 presents the resulting customer counts by customer segment.

Table 3-4: Summary of Large C&I Segment

Segment	DEC Number of Accounts	DEP Number of Accounts
Assembly	5	3
College and University	16	2
Data Center	21	6
Grocery	-	1
Healthcare	1	6
Hospitals	13	4
Institutional	4	14
Lodging/Hospitality	-	-
Miscellaneous	7	2
Office	17	14
Restaurants	-	-
Retail	5	6
Schools K-12	1	5
Warehouse	3	1

Segment	DEC Number of Accounts	DEP Number of Accounts
Agriculture and Assembly	-	7
Chemicals and Plastics	26	35
Construction	-	-
Electrical and Electronic Equip.	9	24
Lumber/Furniture/Pulp/Paper	18	27
Metal Products and Machinery	26	16
Miscellaneous Manufacturing	18	42
Primary Resources Industries	-	5
Stone/Clay/Glass/Concrete	19	8
Textiles and Leather	31	16
Transportation Equipment	11	3
Water and Wastewater	8	7
Total	**259**	**254**

3.3.2. Residential Accounts

RI segmented residential accounts to align DSM opportunities with appropriate DSM measures. Residential segments are based on customer dwelling type (single family or multifamily). The resulting distribution of customers and total electricity consumption by each segment is presented below in Table 3-5 and Table 3-6.

Table 3-5: DEC Residential Market Characteristics by Type of Dwelling Unit

Attribute	Single Family	Multi-Family
Customer Count	86.8%	13.2%
Total kWh Consumption	89.7%	10.3%

Table 3-6: DEP Residential Market Characteristics by Type of Dwelling Unit

Attribute	Single Family	Multi-Family
Customer Count	79%	21%
Total kWh Consumption	91%	9%

Figure 3-1 and Figure 3-2 present a visual representation of this information. Both the DEC and DEP territories in North Carolina consist primarily of single-family dwellings, which have the greater share of both accounts and consumption.

Figure 3-1: DEC Residential Market Characteristics by Type of Dwelling Unit

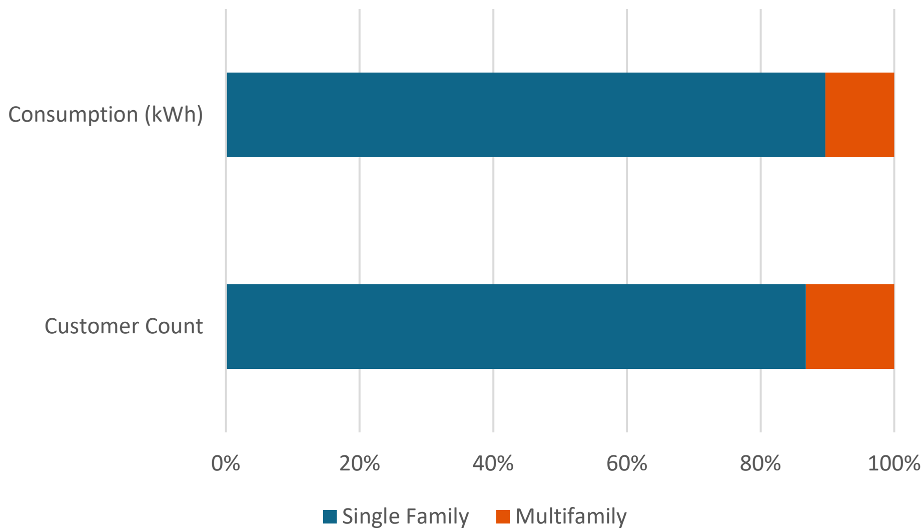
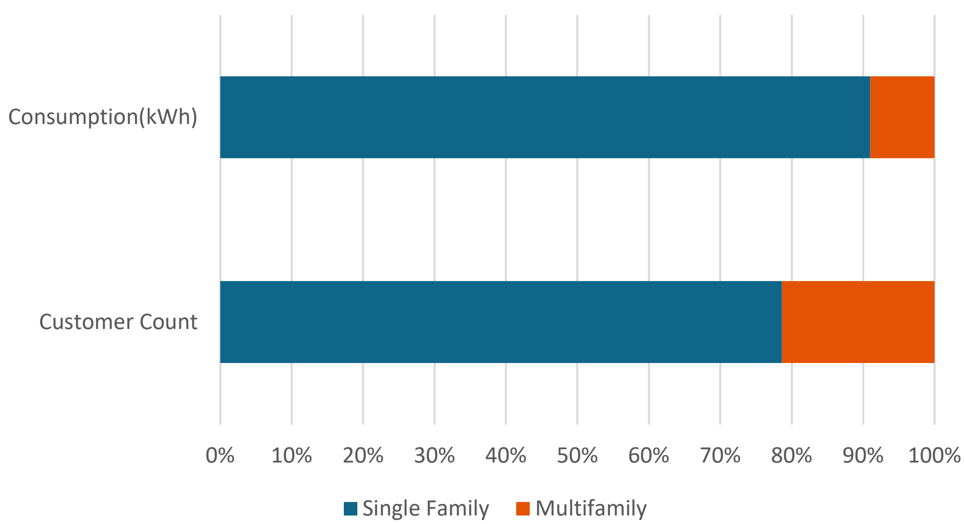


Figure 3-2: DEP Residential Market Characteristics by Type of Dwelling Unit



The DSM assessment required the use of interval data to estimate the loads associated with space cooling, space heating, water heating, and pool pumps. For this study, interval data were available from Duke Energy's load research sample[2].

[2] RI received a sample of 745 premises for DEC (NC and SC combined) and 428 premises for DEP (NC and SC combined).

The residential sector was segmented into three different groups based on annual consumption. Within each of these customer groups, heating and cooling load profiles were estimated using observed AMI consumption data and weather data. The residential customer segments were further segmented between customers who had electric heating and gas heating (i.e., customers who do not have a controllable load during winter peaks), producing a total of six residential customer segments. Cooling loads for electric and gas heating customers were assumed to be identical for each of the corresponding consumption bins.

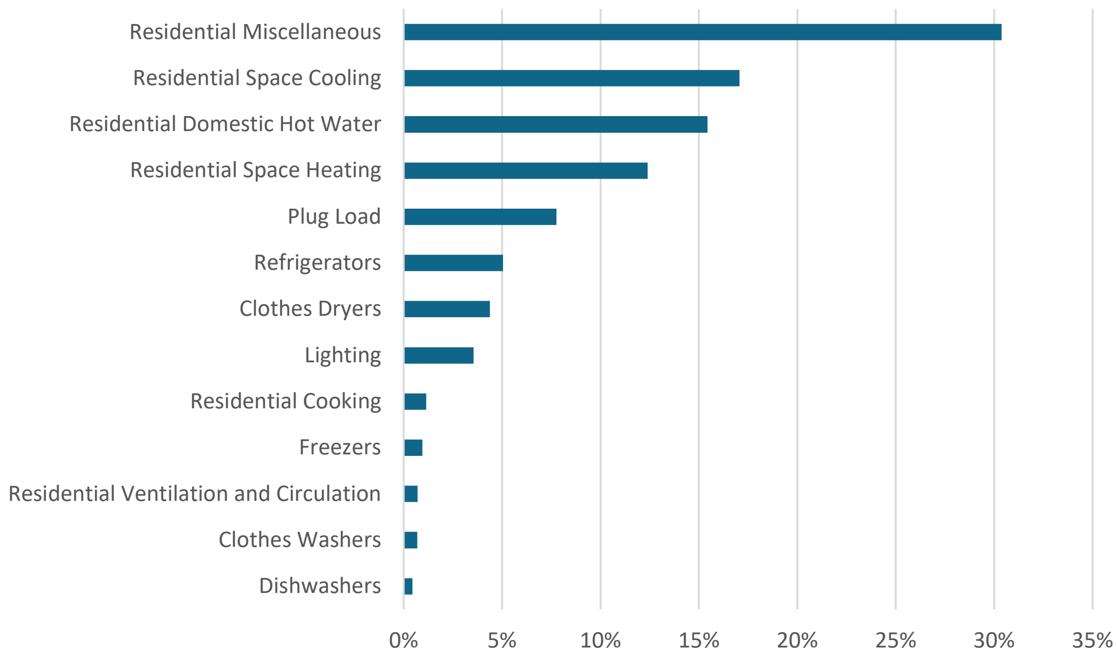
3.4. Base Year 2021 Disaggregated Sales

Duke Energy provided Resource Innovations with an end use forecast for residential customers and a forecast of sales by customer segment for non-residential customers. These forecasts are based in part on the Energy Information Administration (EIA) research activities in the residential, commercial, and manufacturing sectors. As of the time of this study the data provided by these products represented the best available secondary data sources for end use consumption within each economic sector. The following secondary data sources were used by RI to disaggregate each sector's loads:

- Residential load disaggregation is based on Duke Energy's estimates of residential end use load shares; this information in turn is derived from the EIA Residential End Use Consumption Survey (RECS), vintage 2015
- Commercial load disaggregation is based on the Commercial Building Energy Consumption Survey (CBECS) and Duke Energy estimates of sales by commercial segment, vintage 2012
- Industrial load disaggregation is based on Manufacturers' Energy Consumption Survey (MECS), vintage 2018

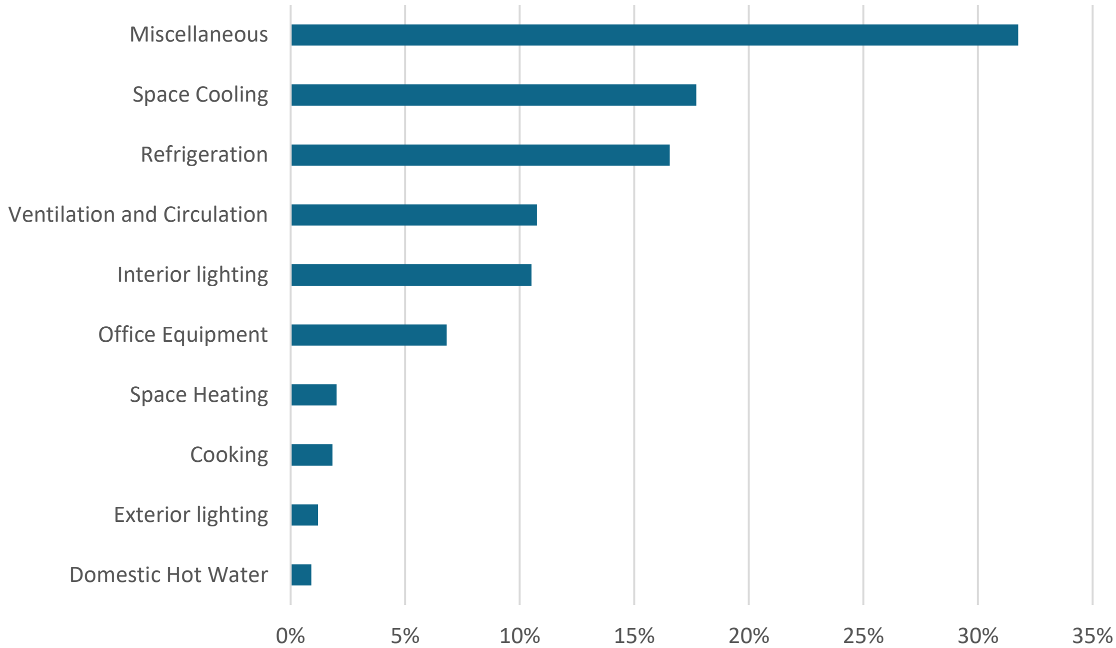
With the details provided by Duke Energy, Resource Innovations was able to identify and categorize some miscellaneous electric loads into an end use category we labelled as "plug loads." Nevertheless, there remains a large share of residential load classified as "residential miscellaneous – other," and no further data are available at this time to further describe this end use. "Residential miscellaneous – other" is one subcategory of the broader residential miscellaneous. Residential miscellaneous also include pool pumps, spas, and ceiling fans as discrete loads that we could identify with available data. Residential miscellaneous loads have historically lacked detail because of the plethora of possible items that might use electricity in this category; in our experience this is not an issue specific to Duke Energy. The disaggregated loads for the base year 2021 residential end uses are summarized in Figure 3-3.

Figure 3-3: DEC 2021 Residential End Uses, Baseline Consumption Shares



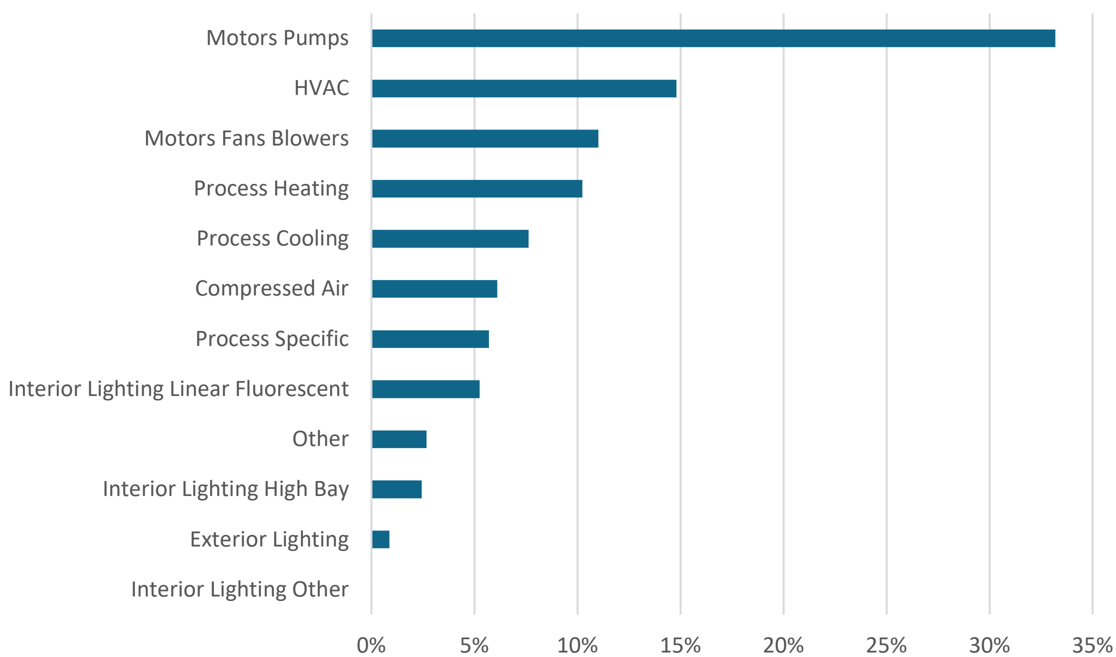
The commercial baseline load shares were constructed with a combination of end use consumption shares from CBECS data, and our estimates of 2021 annual billed consumption by commercial customer type (e.g., building type or segment). Figure 3-4 presents a summary of the end use consumption data available for the commercial sector.

Figure 3-4: DEC Commercial Baseline Load Shares



Industrial customer consumption shares are based on the 2018 EIA MECS survey and Duke Energy billed consumption in 2021. Figure 3-5 presents a summary of industrial customers' end use consumption.

Figure 3-5: DEC Industrial Baseline Load Shares



In the base year 2021, the top end use consumption categories for each economic sector are as follows:

- ***Residential:*** Miscellaneous, space cooling, domestic hot water
- ***Commercial:*** miscellaneous, space cooling, refrigeration
- ***Industrial:*** motors pumps, HVAC, and motors fans blowers

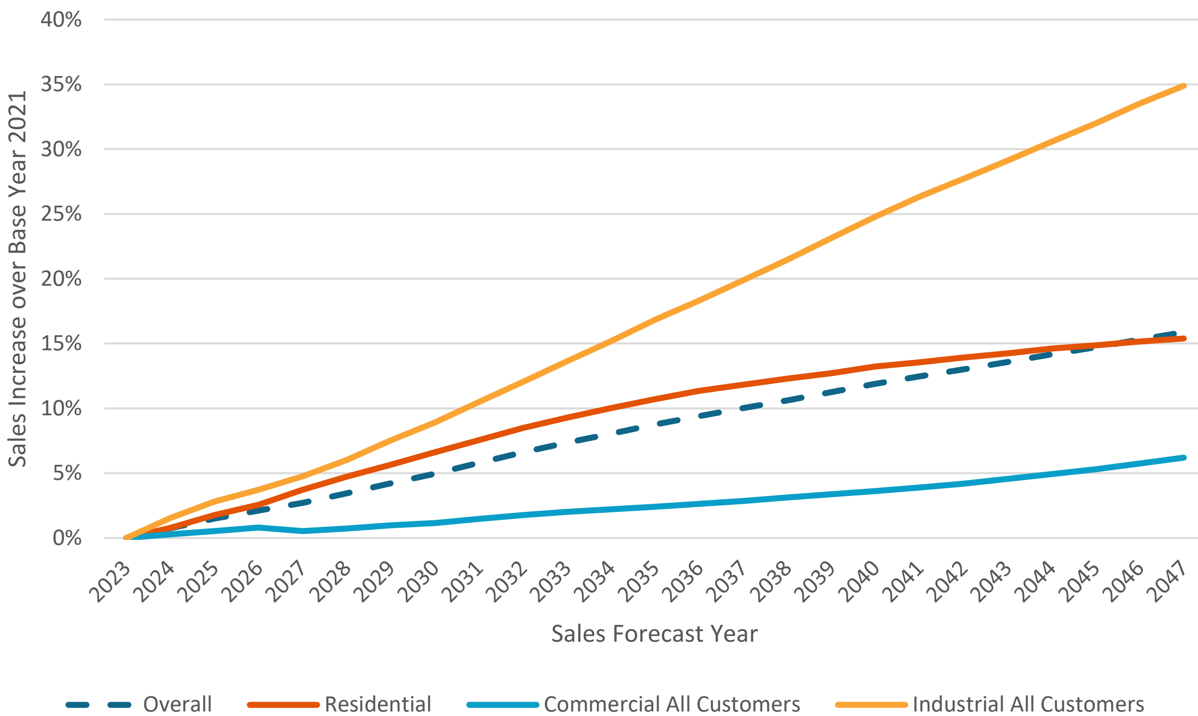
3.5. DEC Sales Forecast 2023 - 2047

3.5.1. DEC System Energy Sales

Duke Energy provided its 2021 vintage sales forecast data to Resource Innovations. Our estimates of energy efficiency potential present savings opportunities relative to this forecast. The forecast of baseline sales used to estimate potential does not include savings from future utility-sponsored energy efficiency,

DEC electricity sales for 2023 are forecasted to be 58,602 GWh, increasing to 67,908 GWh in 2047. This increase of 9,306 GWh represents a change of 16% over the period, or 0.6% average annual growth. The industrial sector is expected to account for the largest share of the increase, growing by 4,273 GWh or 1.3% annually, to reach 16,522 GWh (an increase of 35%) over the 25-year period. The commercial sector is expected to increase by 1,419 GWh to reach 24,299 GWh, a change of 6% over the 25-year period (0.3% annually). The residential sector is forecasted to increase by 3,613 GWh (15%) at an average annual growth rate of 0.6%. Figure 3-6 illustrates the growth rate of sales for each economic sector over the period of analysis. In 2047 the residential sector accounts for 40% of total electricity sales, the commercial sector 36% and the industrial sector 24%.

Figure 3-6: DEC Electricity Sales Growth over Base Year, by Economic Sector, for 2023 - 2047



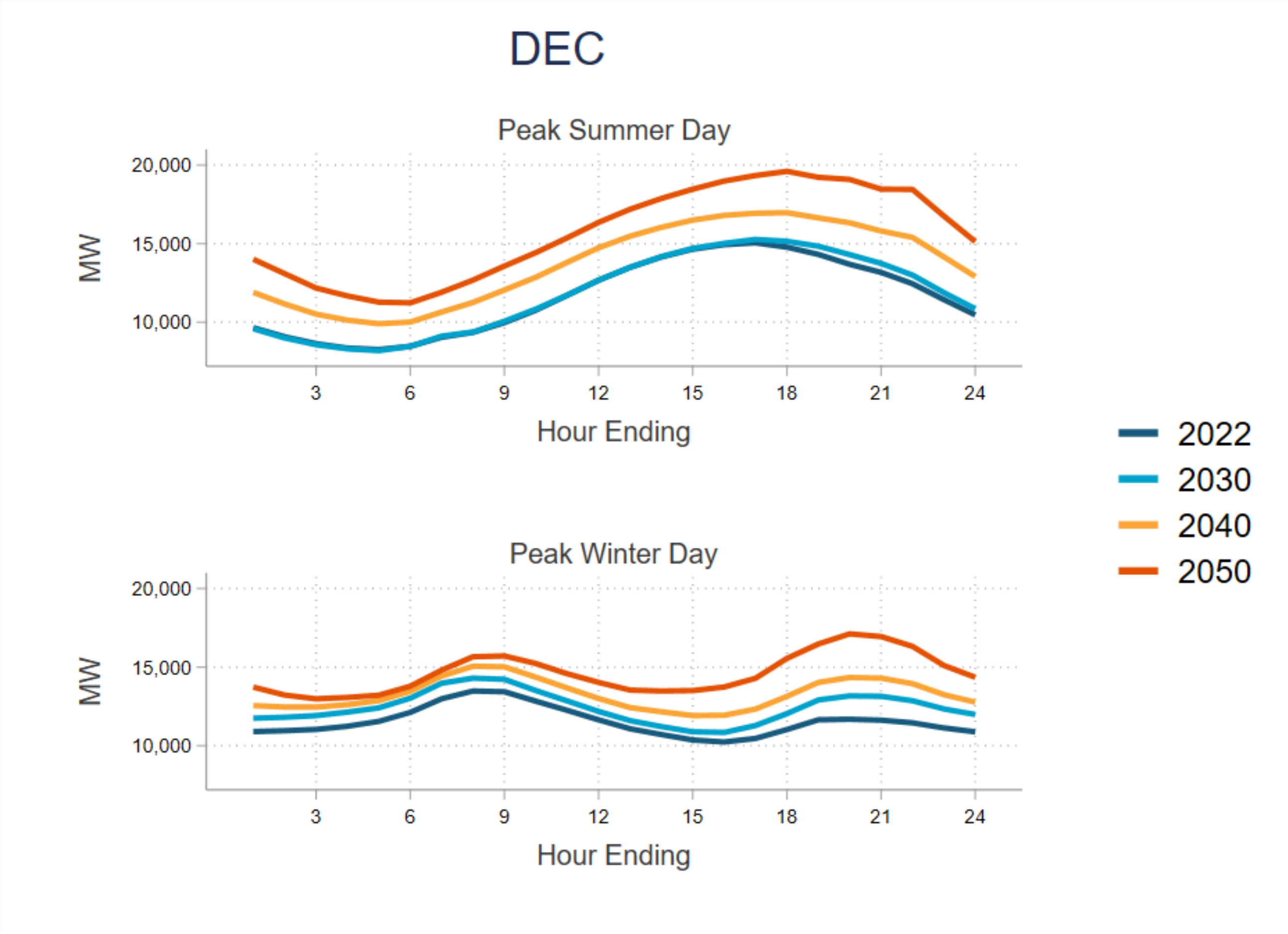
3.5.2. DEC System Demand

Estimating technical potential for demand response resources requires knowing how much load is available to be curtailed or shifted during system peak demand conditions. Demand response benefits accrue from avoiding costly investments to meet peak loads; load reductions have lower value if they occur outside the hours of peak system demand. Our estimates of market potential for demand response are based on when load reductions will most likely be needed throughout the year.

The primary data source used to determine when demand response resources will be needed was the DEC system load forecast. This forecast projects loads for all 8,760 hours of each forecast year available to represent the MPS study period (2023-2047). Figure 3-7 represents an initial inspection of the data. Each figure shows the expected system load profiles for two distinct types of days: peak summer days and peak winter days. Summer was defined as June-September and winter as November-February, while the peak days refer to the day with the maximum demand during the year and season.

Figure 3-7: DEC System Load Forecast by Year (2022, 2030, 2040 and 2050)[3]

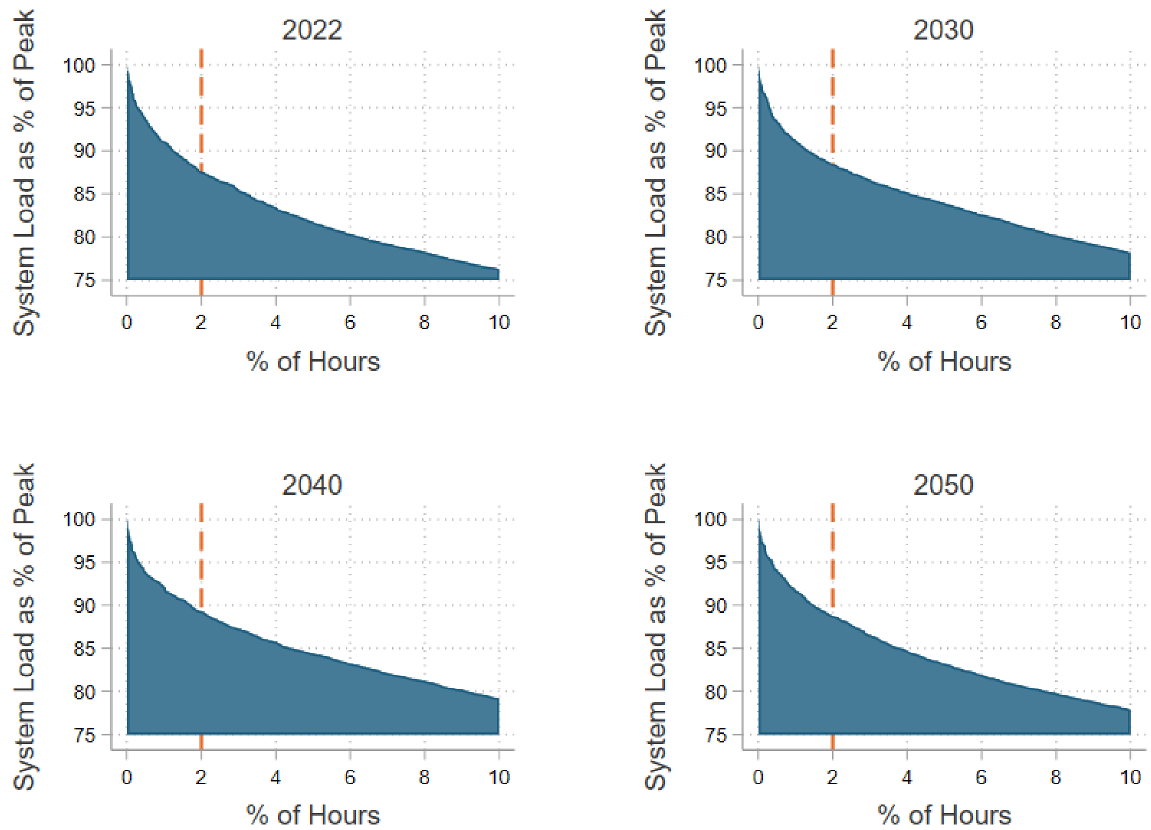
[3] The system load forecast is North Carolina and South Carolina combined, and its projected retail demand which excludes energy efficiency, electric vehicle and solar impacts per Duke Energy.



Several patterns are apparent from examining the figure above. First and foremost, forecasted loads shapes are relatively unchanged over time as the total magnitude of projected load increases. These data indicate summer peak loads are higher than winter peak loads. The peak hour in summer is 5-6 pm and the peak hours in winter are 7-9 am in the morning and around 8 pm at night. The winter peak loads at night are more pronounced in 2050 than the current winter peak loads in 7-9 am. This potential study therefore focuses on the current summer peak hour, 5-6 pm, and the current winter peak hour, 7-8 am.

Though useful for assessing patterns in system loads, Figure 3-7 does not provide information about the concentration of peak loads. A useful tool to examine peak load concentration is a load duration curve, which is presented for 2022, 2030, 2040 and 2050 in: Figure 3-8. This curve shows the top 10% of hourly loads as a percentage of the system's peak hourly usage, sorted from highest to lowest.

Figure 3-8: DEC Forecasted Load Duration Curve by Year



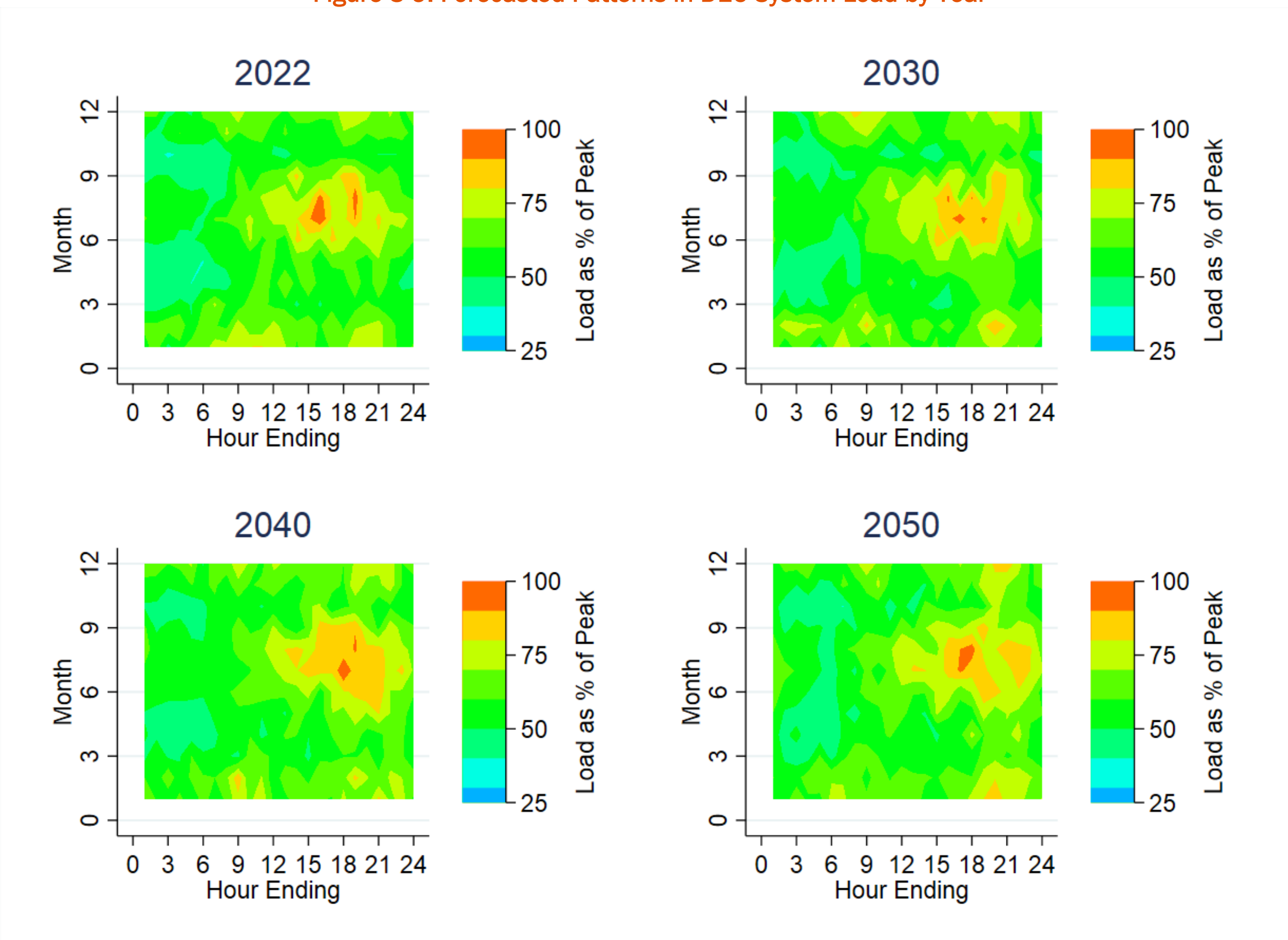
The x-axis in Figure 3-8 is depicted as the cumulative percentage of hours. The orange dotted line drawn at 2% serves as a helpful reference point for interpretation by showing the amount of peak capacity needed to serve the 2% of hours with the highest usage.[4] The DEC system currently uses 13% of peak capacity to serve only 2% of hours and is projected to use around 12% of peak capacity to serve 2% of hours by 2050. This means that overall DEC's peak is expected to remain the same or become slightly less concentrated over time.

Another valuable tool for studying peak loads is a contour plot. Often referred to as "heat maps", these plots show frequencies or intensities of a particular variable for different combinations of two other variables. Figure 3-9 contains the same hourly data as a percentage of peak system load that is presented in: Figure 3-8; however, it shows the months and hours when each hourly load occurs for all hours instead of only the top 10% of hours.

[4] Another interpretation of the load duration curve data would be the amount that peak load capacity could be reduced by shaving demand during 2% of the hours throughout the year.

The results in Figure 3-9 show the highest hours of usage are concentrated in summer evening hours. Actual weather patterns reflect year to year variation in loads and depending on the extreme temperatures for a year, winter peaks can still be of concern. Another consideration is market prices, which can be high in winter if natural gas is used both for heating and electricity generation.

Figure 3-9: Forecasted Patterns in DEC System Load by Year



3.5.3. DEC Customer Opt-Outs

Duke Energy's energy efficiency programs in North Carolina include an "opt-out" provision approved by the North Carolina Utilities Commission. This provision allows non-residential customers receiving electric service at a single site demanding more than 1 megawatt of electric capacity to opt out, along with all accounts in contiguous property. This opt-out provision exempts the customer from the cost recovery mechanism but also eliminates that customer's eligibility for participation in the program.

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke Energy provided RI with current opt-out information for North Carolina, which showed an opt-out rate of approximately 48% of commercial sales and 77% of industrial sales in the DECNC service territory. We incorporated this opt-out rate into the MPS by excluding sales to non-residential customers that opted out, and we applied the applicable energy efficiency technologies and market adoption rates to the remaining customer base.

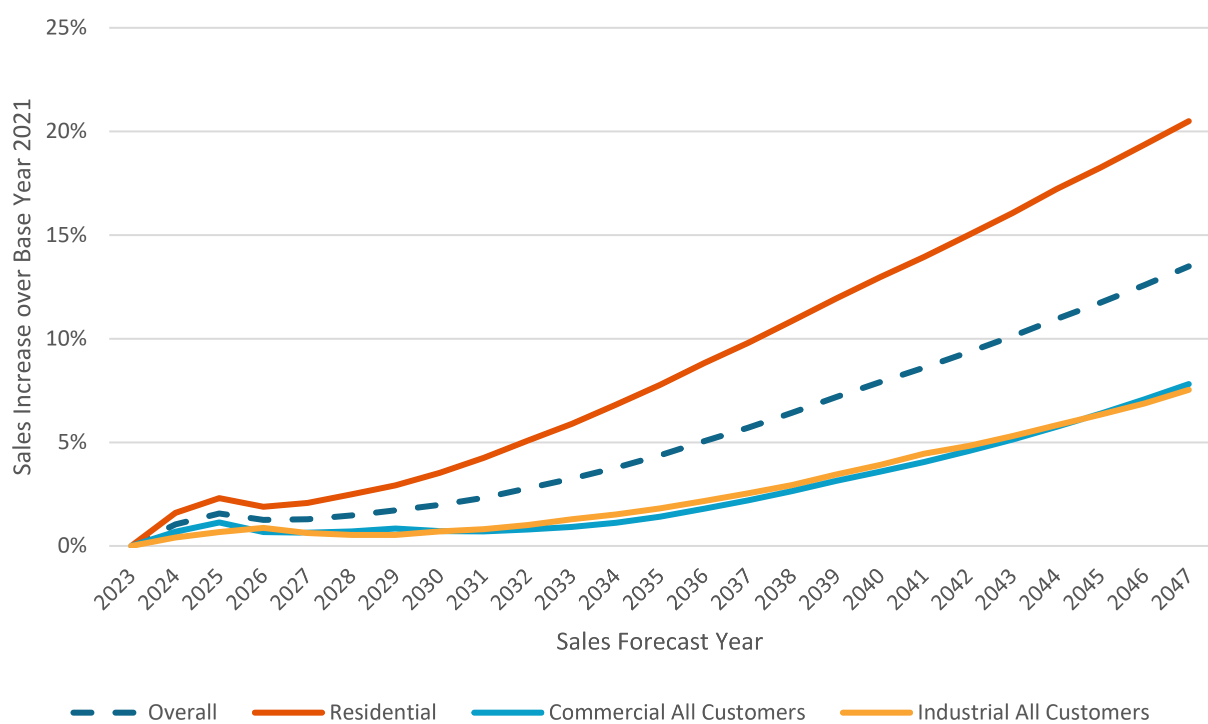
3.6. DEP System Load Forecast 2023 - 2047

3.6.1. DEP System Energy Sales

Duke Energy provided its 2021 vintage sales forecast data to Resource Innovations. Our estimates of energy efficiency potential present savings opportunities relative to this forecast. The forecast of baseline sales used to estimate potential does not include savings from future utility-sponsored energy efficiency,

DEP forecasts electricity sales growth at an annual average rate of 0.5% over the study period, from 36,919 GWh to 41,890 GWh, for a total increase of 13%. DEP Residential sales are the largest category for growth, with a 20% increase of 3,423, or an average annual growth of 0.8%. Commercial sales are expected to grow by 8% to 967 GWh, or 0.3% annually. The average annual growth rate for the Industrial sector is also 0.3%, representing an 8% increase of 590 GWh. These sales forecasts are presented in Figure 3-10.

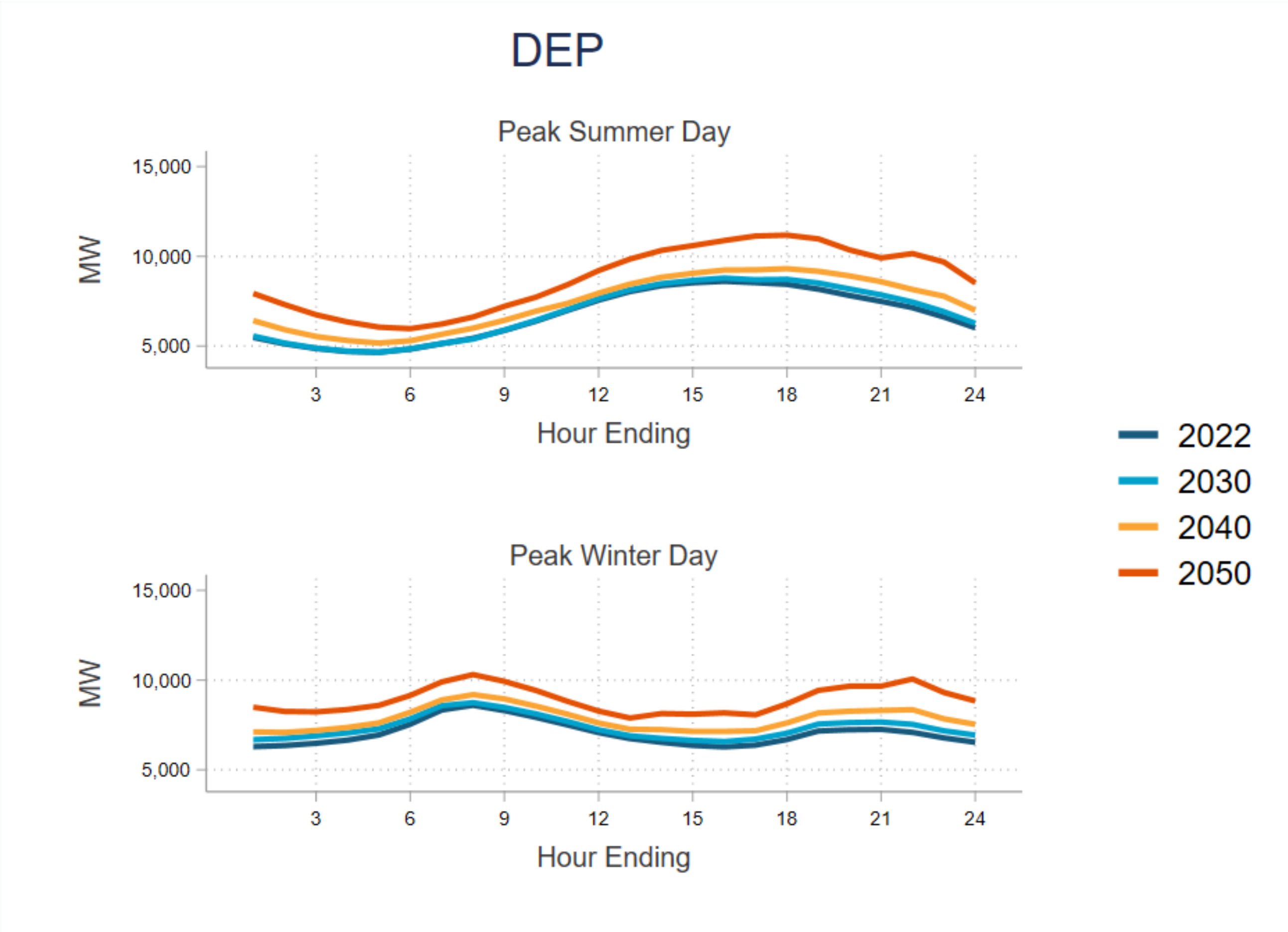
Figure 3-10: DEP Electricity Sales Growth over Base Year, by Economic Sector, for 2023 - 2047



3.6.2. DEP System Demand

As with DEC, the primary data source used to determine when DSM resources will be needed was the DEP system load forecast. This forecast contains forecasted loads for all 8,760 hours of each year in the study period (2023-2047). Figure 3-11 represents an initial inspection of the data. Each figure shows the expected average load profiles for two distinct types of days: peak summer days and peak winter days. Summer was defined as June-September and winter as November-February, while the peak days refer to the day with the maximum demand during the year and season.

Figure 3-11: DEP System Load Forecast by Year (2022, 2030, 2040 and 2050)[5]



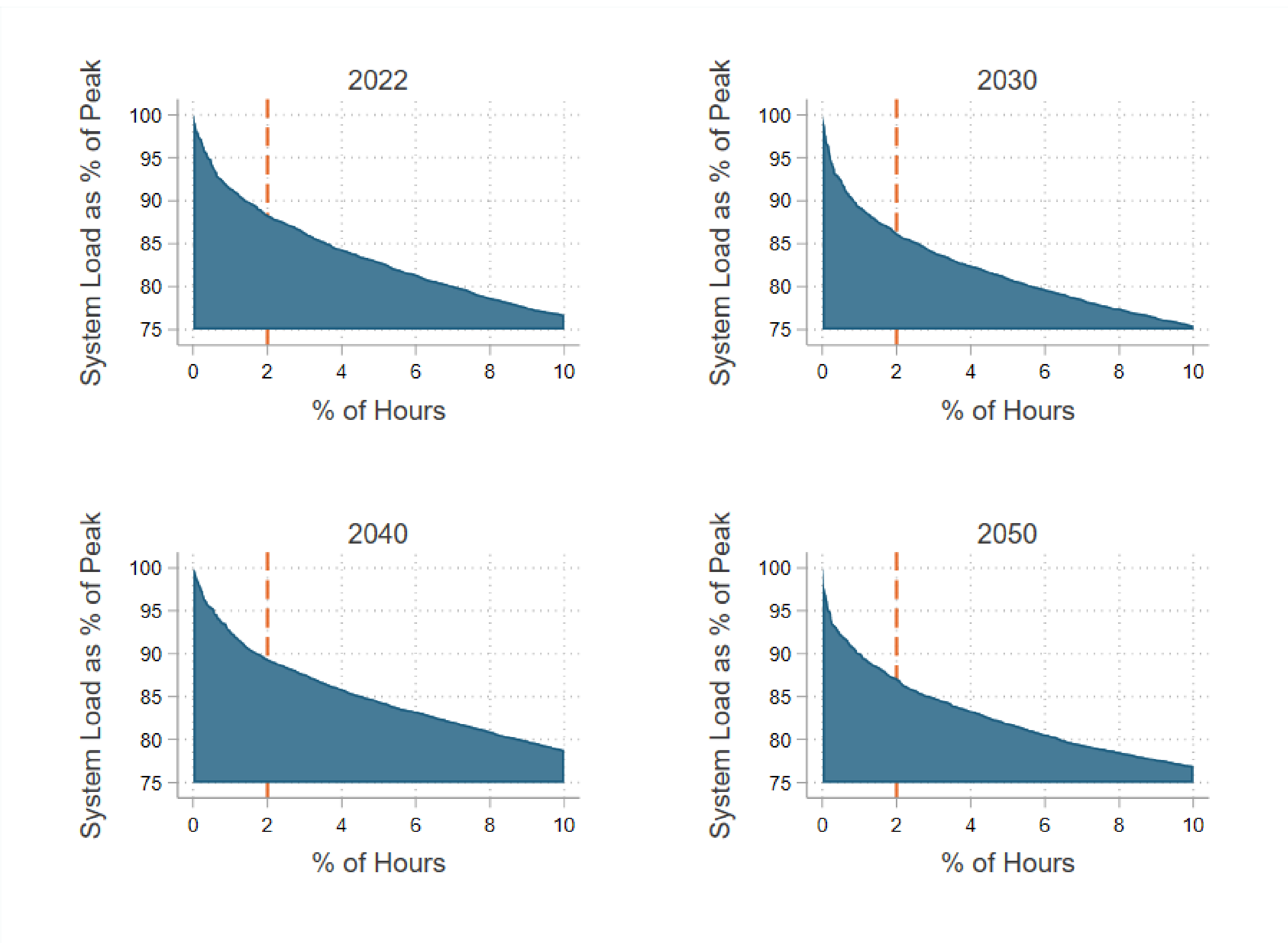
Several patterns are apparent from examining the figure above. First and foremost, similar to what observed in DEC, forecasted loads shapes are relatively unchanged over time as the total magnitude of projected load increases. And summer peak loads are slightly higher than winter

[5] The system load forecast is North Carolina and South Carolina combined, and its projected retail demand which excludes energy efficiency, electric vehicle and solar impacts per Duke Energy.

peak loads. The summer peak hours tend to shift to a later time in 2050, and we observed pronounced, secondary peak hours at night in winter starting 2040. The current peak hour in summer is 3-4 pm and the peak hour in winter is 7-8 am. In 2050, the winter peak loads during 9-10 pm approach the primary peak loads at 7-8 am. This potential study, however, focuses on the current summer peak hour, 3-4 pm, and the current winter peak hour, 7-8 am.

The DEP load duration curve is presented in Figure 3-12 for 2022, 2030, 2040 and 2050. This curve shows the top 10% of hourly loads as a percentage of the system's peak hourly usage, sorted from highest to lowest.

Figure 3-12: DEP Forecasted Load Duration Curve by Year



The x-axis in Figure 3-12 is depicted as the cumulative percentage of hours. The orange dotted line drawn at 2% serves as a helpful reference point for interpretation by showing the amount of peak capacity needed to serve the 2% of hours with the highest usage.[6] The DEP system

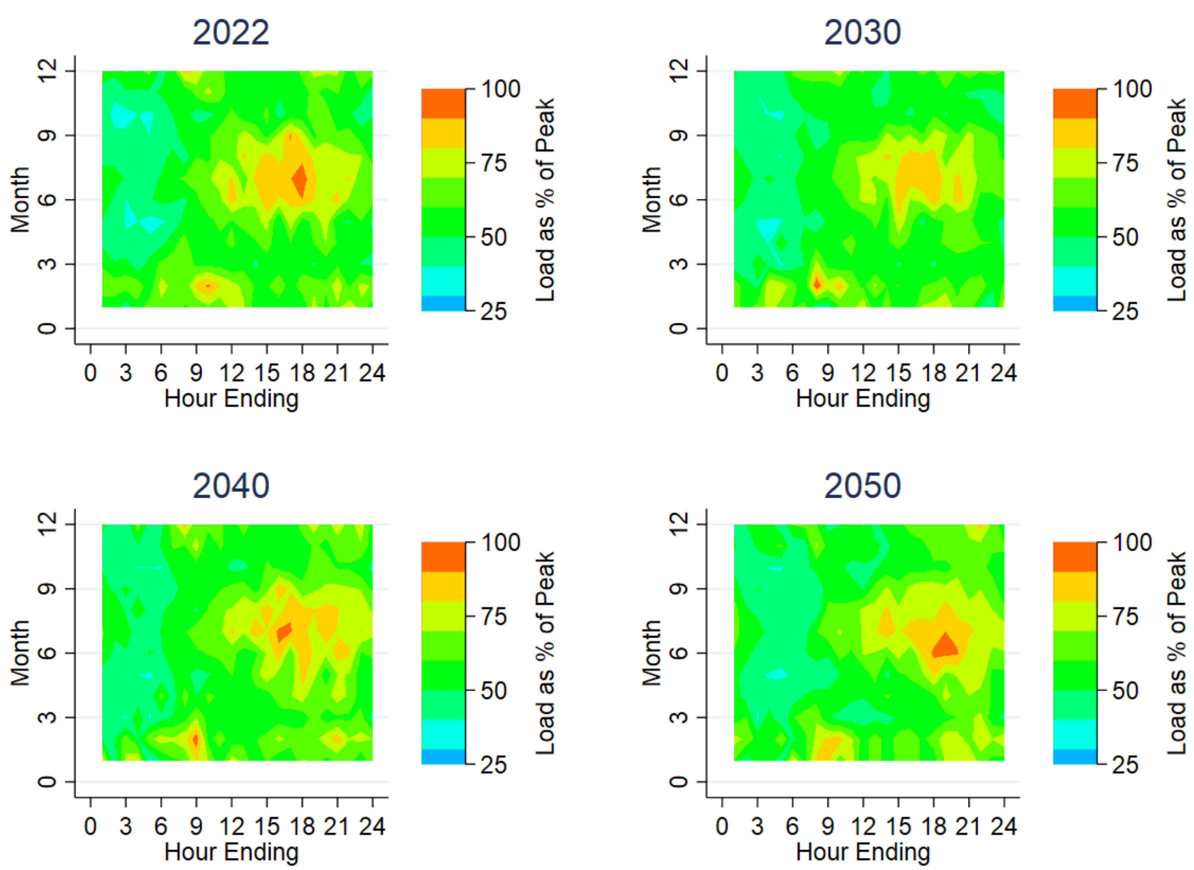
[6] Another interpretation of the load duration curve data would be the amount that peak load capacity could be reduced by shaving demand during 2% of the hours throughout the year.

currently uses 12% of peak capacity to serve only 2% of hours and is projected to use around 14% of peak capacity to serve 2% of hours by 2050. This means that overall DEP's peak is expected to remain the same or become slightly more concentrated over time.

Figure 3-13, the contour plot, contains the same hourly data as a percentage of peak system load that is presented in: Figure 3-12; however, it shows the months and hours when each hourly load occurs for all hours instead of only the top 10% of hours.

The results in Figure 3-13 show the highest hours of usage are concentrated in summer afternoon hours and winter morning hours. In winter, we see the peak is particularly during the 8-9 am when a high residential heating load is expected.

Figure 3-13: Forecasted Patterns in DEP System Load by Year



3.6.3. DEP Customer Opt-Outs

Duke Energy's energy efficiency programs in North Carolina include an "opt-out" provision approved by the North Carolina Utilities Commission. This provision allows non-residential customers receiving electric service at a single site, with at least one meter constituting more than 1 megawatt of electric capacity to opt out, along with all accounts in contiguous property. This opt-out provision exempts the customer from cost recovery mechanism but also eliminates that customer's eligibility for participation in the program.

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke Energy provided RI with current opt-out information for North Carolina, which showed an opt-out rate of approximately 44% of commercial sales and 74% of industrial sales in the DEPNC service territory. We incorporated this opt-out rate into the model by reducing the non-residential sales estimates by the appropriate percentage and applying the applicable energy efficiency technologies and market adoption rates to the remaining sales forecast.

4. Measure List

RI maintains a database of energy efficiency measures for MPS studies. Measure data are refined as new data or algorithms are developed for estimating measure impacts. The current list of savings opportunities, or “measures,” incorporates the measure list used in the 2020 MPS study RI conducted on behalf of Duke Energy. We added or subtracted measures at the request of project stakeholders or as a result of changes to the EE marketplace (for example, codes and standards, or current practice in the market). An example of measure list updates is that many lighting end uses or applications now use an LED lamp type as the baseline, as new Energy Independence and Security Act regulations take effect in the marketplace. This section describes how the measure data is developed, maintained, and applied in the study for energy efficiency and DSM services and products.

The EE measure data used in the 2023 MPS study includes a list of proposed measures that has been reviewed many times by many project stakeholders in multiple jurisdictions. Resource Innovations curates a database of EE measures that we update each time we conduct a market potential study. Updates for this project included sharing the measure list with the Carolinas EE/DSM Collaborative members to solicit proposed measure additions. We requested, received, and responded to Collaborative input concerning measures to be included in the study. We also presented detailed information on the measure research process, and we requested feedback and comments from Collaborative members on the same; we received no suggestions to modify the process from the Collaborative. After conducting measure research, we reported to the collaborative on the algorithm for estimating measure impacts for each measure in the study, as well as algorithm parameter values used to calculate the impact estimates. The EE/DSM Collaborative provided comments/responses concerning the parameter values, to which we also responded before proceeding with the subsequent tasks in the study.

Measures included in this study represent opportunities to reduce consumption across all major electricity end uses and customer types. The MPS does not include measures related to fuel switching (e.g., converting from gas space heating to electric space heating). This scope of measures is reasonable because the MPS applies the UCT to screen measures for economic potential; measures are assigned to utility-sponsored programs and screened to ensure they are cost-effective for Duke Energy to offer in a utility-sponsored program for energy efficiency.

The measures included in the study are those currently available for purchase in today’s market. The MPS does not speculate on future technologies but does include many nascent or novel savings opportunities such as smart panels (added at the request of the Collaborative), networked lighting controls, heat pump water heaters, and others. All measure impacts are modeled as a percentage reduction in baseline energy consumption. The MPS model also includes a stock and flow calculation for equipment burnouts or turnover. Future measure impacts are applied to a future baseline energy consumption estimate that reflects a continuation of historical and current trends. In this manner our estimates of savings potential are incremental to naturally occurring energy efficiency savings captured by the Duke Energy sales forecast.

The final measure list included energy efficiency technologies and products that enable DSM opportunities. DSM initiatives that do not rely on installing a specific technology, such as time-of-use rates and permanent load shifting, are not examined in the DSM potential estimates.

4.1. Energy Efficiency Measures

RI's measure data represents savings opportunities for all electricity end uses and customer types. EE program measure offers are typically more specific than those required to assess EE potential. For example, Duke Energy programs have historically had multiple instances of LED lamps with varying characteristics (candelabra base, globe base, A-line, etc.). Although these distinctions are important during program delivery, this level of granularity is not necessary to identify the market potential for EE savings.

RI used a qualitative screening approach to assess emerging technologies for the North Carolina service territories. The qualitative screening criteria that RI used included: difficult to quantify savings, no longer current practice, better measure available, immature or unproven technology, limited applicability, poor customer acceptance, health and environmental concerns, and end-use service degradation. If we were able to identify specific products and generate estimates of measure savings for emerging technologies, then we added them to the measure list. RI updated its online measure database to support this study. RI's database contains the following information for each measure:

- Classification of measure by type, end use, and subsector
- Description of the base-case and the efficiency-case scenarios
- Measure life
- Savings algorithms and calculations per subsector, taking weather zones and subsectors into consideration
- Input values for variables used to calculate energy savings
- Measure costs
- Output to be used as input in RI's TEAPOT model.

Detailed measure assumptions in this database were provided to Duke Energy and the Carolinas EE/DSM Collaborative. As shown in Table 4-1, the study included 386 unique energy efficiency measures. Expanding the measures to account for all relevant combinations of segments, end uses, and construction types resulted in 9,790 measure permutations that we modeled against the market baseline.

Table 4-1: EE Measure Counts by Sector

Sector	Unique Measures	Permutations
Residential	107	814
Commercial	166	5,658
Industrial	113	3,318
Total	386	9,790

4.2. DSM Services and Products

RI and Duke Energy worked together to determine which DSM products and services were included in the MPS, and addressed the following:

- **Direct load control.** Customers receive incentive payments for allowing the utility a degree of control over equipment, such as air conditioners or water heaters. This includes both switch-based programs and smart thermostat programs.
- **Emergency load response.** Customers receive payments for committing to reduce load if called upon to do so by the grid operator.
- **Economic load response:** Utilities provide customers with incentives to reduce energy consumption when marginal generation costs are higher than the incentive amount required to achieve the needed energy reduction.
- **Base interruptible DR**. Customers receive a discounted rate for agreeing to reduce load to a firm service level upon request.
- **Automated DR**. Utility dispatched control of specific end-uses at customer facilities.

5. Technical Potential

Technical potential relates to base year load shares and reference case load forecasts for 2023 to 2047. Measure savings impacts are applied to the baseline data to estimate technical potential. The technical potential scenario estimates the savings potential when all technically feasible energy efficiency measures are fully implemented, while accounting for equipment turnover. This savings potential can be considered the maximum reduction attainable with available technology and current market conditions (e.g., currently available technology, building stock, and end uses as reflected in Duke Energy forecasted sales). EE and DSM potential scenarios that account for measures' costs and benefits and market adoption are discussed in subsequent report sections for economic potential and achievable potential, respectively.

5.1. Approach and Context

Technical potential represents a straightforward application of EE and DSM measures to the baseline market context for Duke Energy Carolinas. Technical potential is determined by the energy intensity of baseline consumption and the savings opportunities represented by EE and DSM measures. Baseline conditions for electricity consumption inherently reflect historic and current economic conditions, the current configuration of the power system, policy context, and customer preferences.

Current and projected sales and load are based on the current and projected numbers of accounts served by economic sector. The types of loads present at these accounts are reflective of customers' economic sector, segment, and final demand for electricity services. Final demand for electricity is reflective of numerous, complex factors such as the set of available technologies that meet electricity end uses (e.g., HVAC for heating, cooling, and ultimately: comfort); the cost of technologies that produce electricity end uses; the price of electricity and other energy sources; customer demand for electricity services; and behavioral or other contextual factors that collectively drive customer decisions about energy consumption.

5.1.1. Energy Efficiency

Energy efficiency technical potential provides a theoretical maximum for electricity savings relative to the forecast baseline. Technical potential ignores all non-technical constraints on electricity savings, such as cost-effectiveness and customer willingness to adopt energy efficiency. For an EE potential study, technical potential refers to delivering less electricity to satisfy the same end uses. In other words, technical potential might be summarized as "doing the same thing with less energy, regardless of the cost."

RI applied estimated energy savings from equipment or non-equipment measures to all electricity end uses and customers. Since technical potential does not consider the costs or time required to achieve these electricity savings, the estimates provide an upper limit on savings potential. RI presents technical potential results as a single numerical value for the DEC service territory and for the DEP service territory.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 5-1 below, while the core equation used in the nonresidential sector technical potential analysis for each individual efficiency measure is shown in Equation 5-2, below.

Equation 5-1: Core Equation for Residential Sector Technical Potential

Technical Potential of Efficient Measures = Total Number of Households × Base Case Equipment Energy Use Intensity (kWh/unit) × Saturation Share × Remaining Factor × Applicability Factor × Savings Factor

Where:

Base Case Equipment Energy Use Intensity = the electricity used per customer per year by each base-case technology in each market segment; efficient technologies are applied to reduce this base case equipment energy use intensity.

Saturation Share = the fraction of the electricity end use consumption that may be reduced by applying an efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (i.e., it may not be possible to install a heat pump water heater for every home due to space constraints).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Equation 5-2: Core Equation for Nonresidential Sector Technical Potential

Technical Potential of Efficient Measures = Total Stock Sq. Footage by Building Type by EDC × Base Case Equipment Energy Use Intensity (kWh/unit) × Equipment Saturation Share × Remaining Factor × Applicability Factor × Savings Factor

Where:

Total Stock Square Footage by Building Type = the forecasted square footage level for a given building type (e.g., office buildings).

Base Case Equipment Energy Use Intensity = the electricity used per square foot per year by each base-case equipment type in each market segment. In other words, the base case equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Equipment Saturation Share = the fraction of the equipment electrical energy that is applicable for the efficient technology in a given market segment. For example, for room air conditioners, the saturation share would be the fraction of all space cooling kWh in a given market segment that is associated with room air conditioner equipment.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. For example, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (i.e., it may not be possible to install VFDs on all motors in a given market segment).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

It is important to note that the technical potential estimate represents electricity savings potential at a specific point in time. In other words, the technical potential estimate is based on data describing *status quo* customer electricity use and technologies known to exist today. As technology and electricity consumption patterns evolve over time, the baseline electricity consumption will also change accordingly. For this reason, technical potential is a discrete estimate of a dynamic market. RI reported technical potential over a defined time period, based on currently known DSM measures and observed electricity consumption patterns.

5.1.1.1.1. Addressing Naturally Occurring Energy Efficiency

Duke Energy's baseline sale forecast includes the impacts of efficiency actions that are expected to occur in the absence of utility intervention. RI worked with Duke Energy's forecasting group to understand how the sales forecasts incorporated two known sources of naturally occurring efficiency:

- **Codes and Standards:** The sales forecasts incorporated the impacts of known code changes. While some code changes have relatively little impact on overall sales, others— particularly the Energy Independence and Security Act (EISA) and other federal legislation—will have noticeable influence. Given the uncertainty associated with the implementation of the EISA backstop and current market trends, RI adjusted the future lighting baseline to the EISA-compliant standard.
- **Baseline Measure Adoption:** Sales forecasts typically exclude the projected impacts of future DSM efforts, but account for baseline efficiency penetration.

By properly accounting for these factors, the potential study represents the difference between the anticipated adoption of efficiency measures as a result of DSM efforts and the "business as usual" adoption rates absent any projected future impacts of utility-sponsored programs. This is true even in the technical and economic scenarios, where adoption was assumed to be 100%, and was particularly important in the achievable potential analysis, where RI estimated the measure adoption in a market featuring utility-sponsored programs.

5.1.2. Demand-side Management

The concept of technical potential applies differently to demand-side management than for energy efficiency. Technical potential for demand-side management is effectively the magnitude of loads that can be managed during conditions when grid operators need peak capacity, ancillary services, or when wholesale energy prices are high. Which accounts are consuming electricity at those times? What end-uses are in play? Can those end use loads be managed? Large C&I accounts generally do not provide the utility with direct control over end-uses. However, businesses will forego virtually all electric demand temporarily if the financial incentive is large enough.

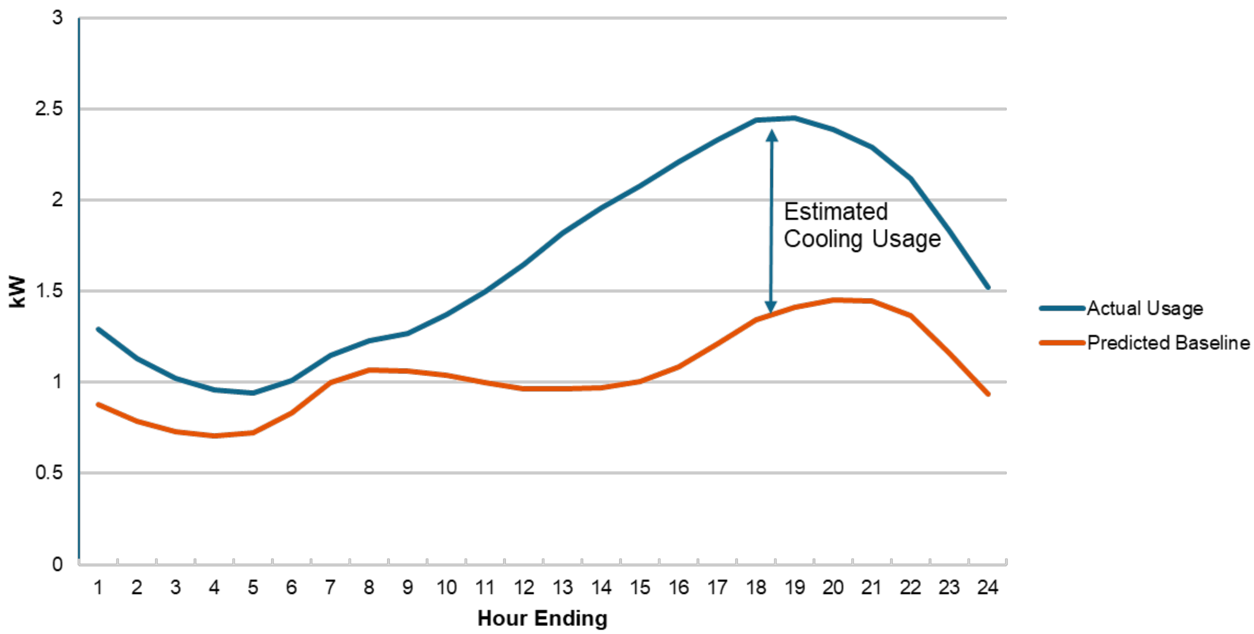
For residential and SMB accounts where DSM means direct utility load control, technical potential for demand-side management is limited by the loads that can be controlled remotely at scale. RI produced disaggregated weather-responsive load for all 8760 hours. This approach identifies weather-responsive customer loads available at times when the different grid applications are needed can vary substantially. Instead of producing disaggregated loads for the average residential customers, the study was produced for several customer segments, thereby allowing the study to identify which customers were cost-effective to recruit and which were not.

RI used interval data for all large C&I customers; and we used interval data from Duke Energy's load research sample for SMB and residential customers. Technical potential, in the context of DSM, is defined as the total amount of load available for reduction that is coincident with the period of interest. In the context of this study, DSM capacity is defined as the system peak hour for the summer and winter seasons. Thus, two sets of capacity values are estimated: a summer capacity and a winter capacity.

As previously mentioned, all large C&I load is considered dispatchable, while residential and SMB DSM capacity is based on specific end uses. For this study, it was assumed that summer DSM capacity for residential customers would be comprised of AC, pool pumps, and water heaters. For SMB customers, summer capacity would be based on AC load. For winter capacity, residential DSM capacity would be based on electric heating loads and water heaters. For SMB customers, winter capacity is comprised all coincident winter loads; this assumption is used to align with the existing Duke Energy SMB "bring-your-own-kW" incentive offers.

AC and heating load profiles for residential customers and AC load profiles for SMB customers were generated with the load research sample provided by Duke Energy. Loads for each sampled customer were combined with historical weather data to estimate hourly load as a function of weather conditions. AC and heating loads were estimated by first calculating the baseline load on days when cooling degree days (CDD) and heating degree days (HDD) were equal to zero, and then subtracting this baseline load. This methodology is illustrated by Figure 5-1 (a similar methodology was used to predict heating loads).

Figure 5-1: Methodology for Estimating Cooling Loads



This method was able to produce estimates for average AC/heating load profiles for several different customer segments within the residential and SMB sectors. Residential customers were categorized by heating type and further segmented into three different groups with each type based on annual energy consumption. SMB customers were segmented into segments based on industry NAICS codes. Profiles for residential water heater and pool pump loads were estimated by utilizing end use load data from NREL's residential end use load shapes[1].

For loads eligible to provide DSM services, system peak hours were identified using 2019 system load data to avoid any impacts from COVID-19. The 2019 summer peak for DEC territory occurred July 16th during hour ending 18. The 2019 winter peak for DEC territory occurred January 22nd during hour ending 8. The 2019 summer peak for DEP territory occurred July 18th during hour ending 16. The 2019 winter peak for DEP territory occurred January 22nd during hour ending 8.

5.2. DEC Energy Efficiency Technical Potential

This section provides the results of the DEC and DEP energy efficiency technical potential for each of the three segments.

[1] End-Use Load Profiles for the U.S. Building Stock from NREL and its research partners. https://www.nrel.gov/buildings/end-use-load-profiles.html

5.2.1. Summary

Table 5-1 summarizes the energy efficiency technical potential by sector and levelized cost associated with the identified potential. RI calculated levelized cost as the discounted sum of incremental cost over the study period divided by the discounted sum of lifetime energy savings over the period.

Table 5-1: DEC Energy Efficiency Technical Potential by Sector

Sector	Technical Potential (2023-2047)			
	Energy (GWh)	% of 2047 Base Sales	Demand (MW)	
			Summer	Winter
Residential	7,378	27%	1,828	1,373
Commercial	3,865	16%	801	371
Industrial	3,205	19%	440	436
Total	**14,448**	**21%**	**3,069**	**2,179**

5.2.2. Sector Details

Figure 5-2 summarizes the DEC residential sector energy efficiency technical potential by end use and customer segment.

Figure 5-2: DEC Residential EE Technical Potential– Cumulative 2047 by End-Use

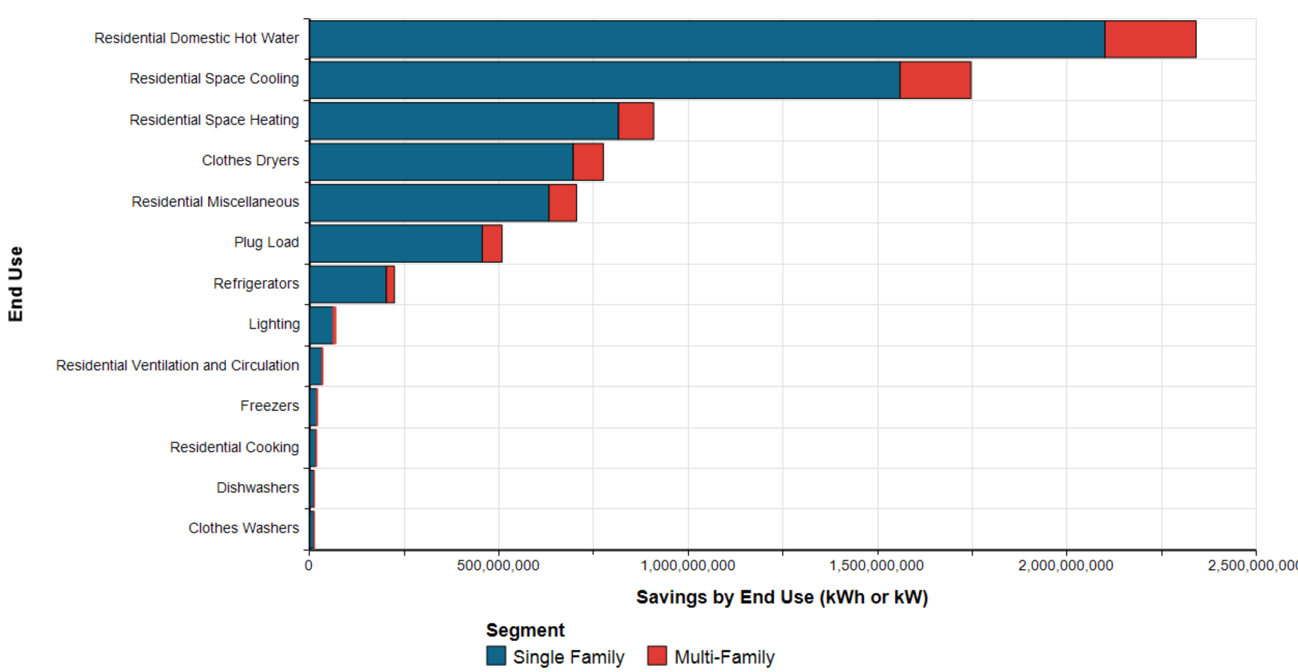


Figure 5-3 summarizes the DEC commercial sector EE technical potential by end use.

Figure 5-3: DEC Commercial EE Technical Potential – Cumulative 2047 by End-Use

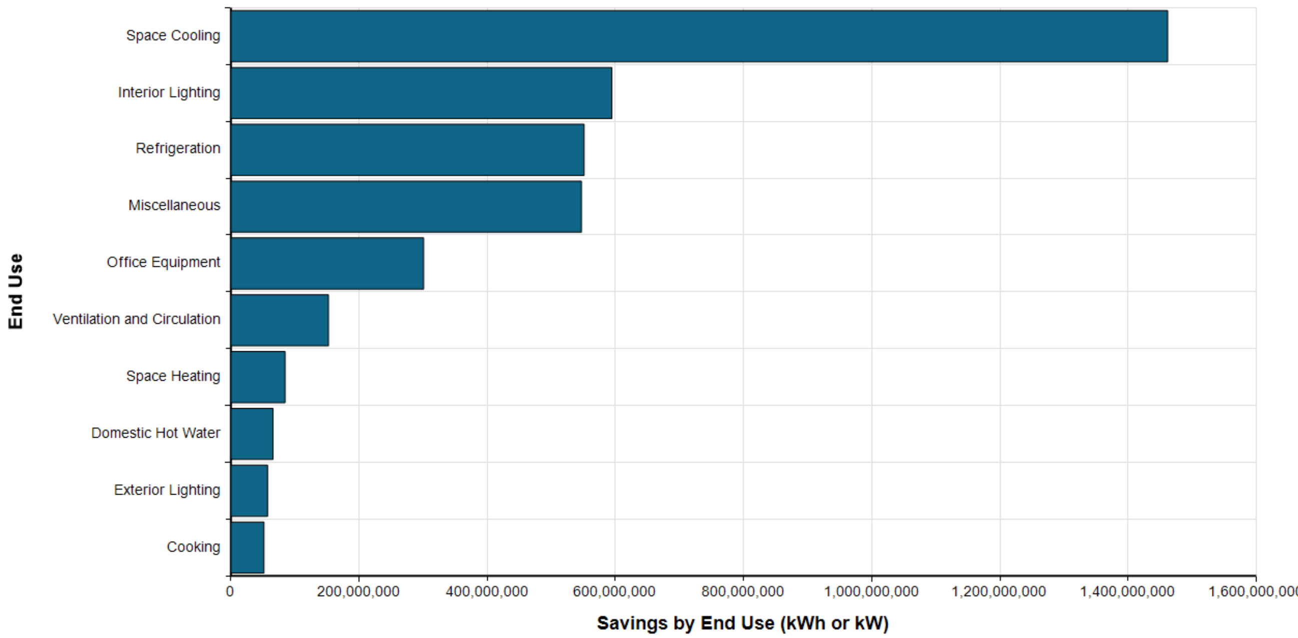


Figure 5-4 provides a summary of DEC energy efficiency technical potential contributions by commercial facility types analyzed in this study.

Figure 5-4: DEC Commercial EE Technical Potential by Segment

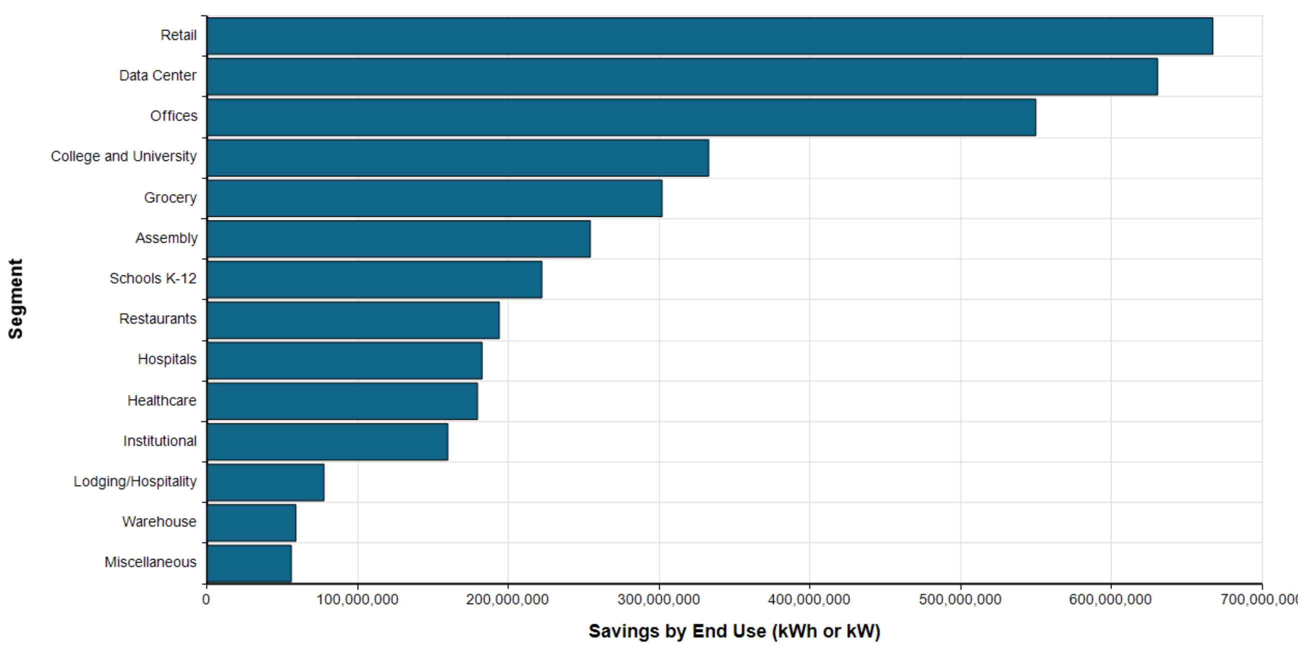


Figure 5-5 summarizes the DEC industrial sector energy efficiency technical potential by end use.

Figure 5-5: DEC Industrial EE Technical Potential – Cumulative 2047 by End-Use

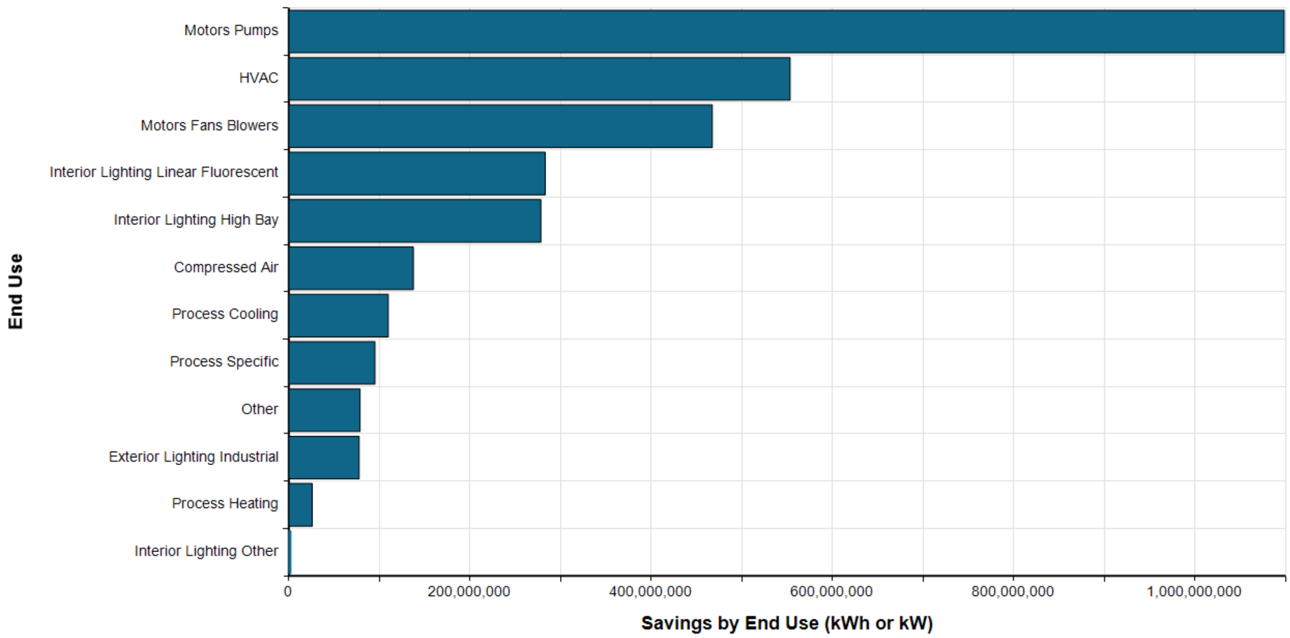
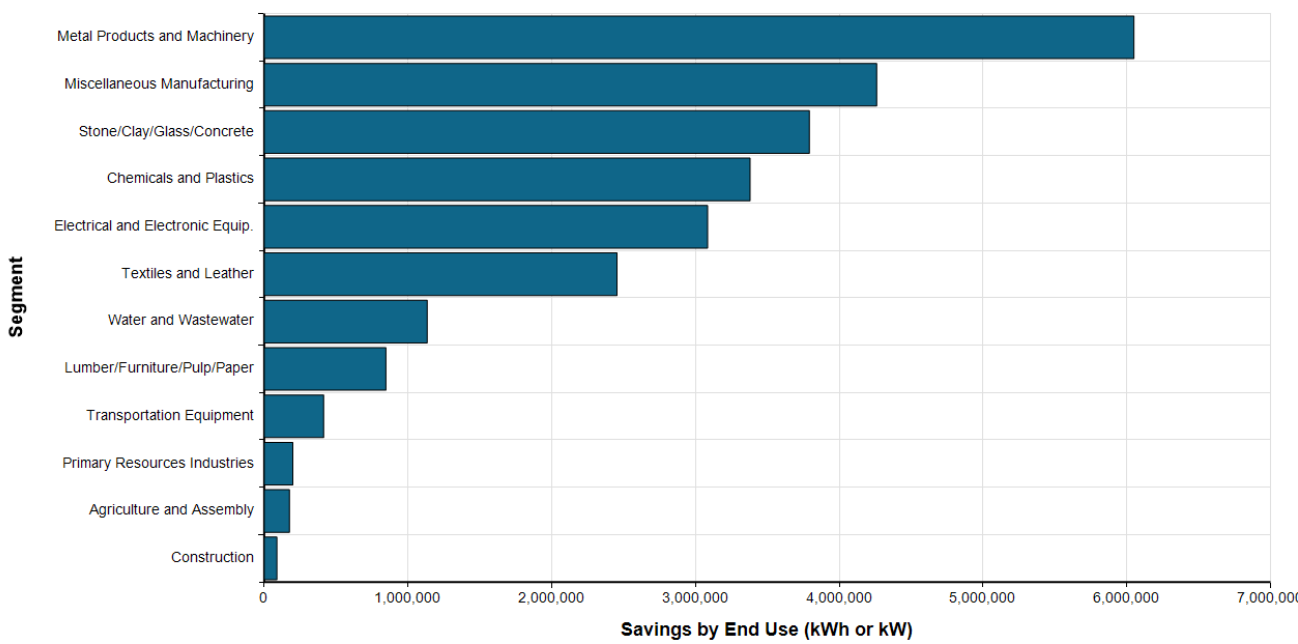


Figure 5-6 provides a summary of DEC energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 5-6: DEC Industrial EE Technical Potential by Segment



5.3. DEP Energy Efficiency Technical Potential

This section provides the results of the DEP energy efficiency technical potential for each of the three economic sectors.

5.3.1. Summary

Table 5-2 summarizes the DEP energy efficiency technical potential by sector and levelized cost associated with the identified potential. RI calculated levelized cost as the sum of incremental cost over the study period divided by the discounted sum of lifetime energy savings over the period.

Table 5-2: DEP Energy Efficiency Technical Potential by Sector

Sector	Technical Potential (2023-2047)			
	Energy (GWh)	% of 2047 Base Sales	Demand (MW)	
			Summer	Winter
Residential	5,434	27%	1,302	1,165
Commercial	2,223	17%	425	213
Industrial	1,277	15%	171	166
Total	**8,934**	**21%**	**1,898**	**1,544**

5.3.2. Sector Details

Figure 5-7 summarizes the DEP residential sector EE technical potential by end use.

Figure 5-7: DEP Residential EE Technical Potential – Cumulative 2047 by End-Use

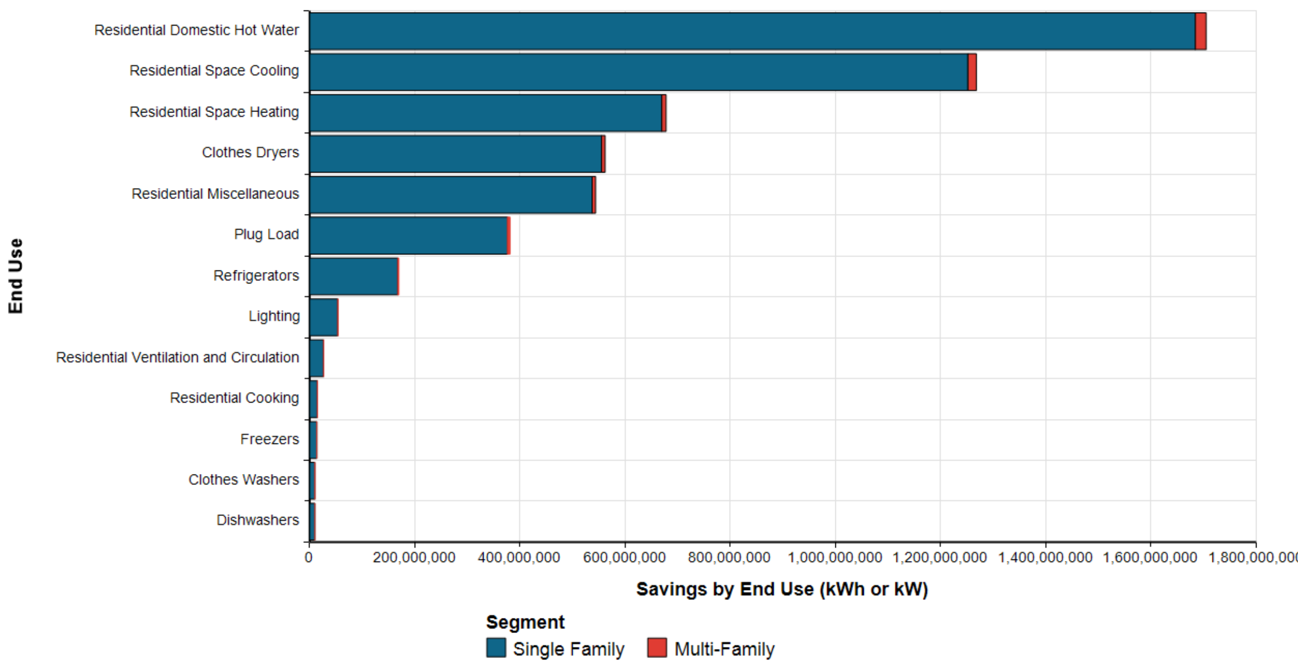


Figure 5-8 summarizes the DEP commercial sector energy efficiency technical potential by end use.

Figure 5-8: DEP Commercial EE Technical Potential – Cumulative 2047 by End-Use

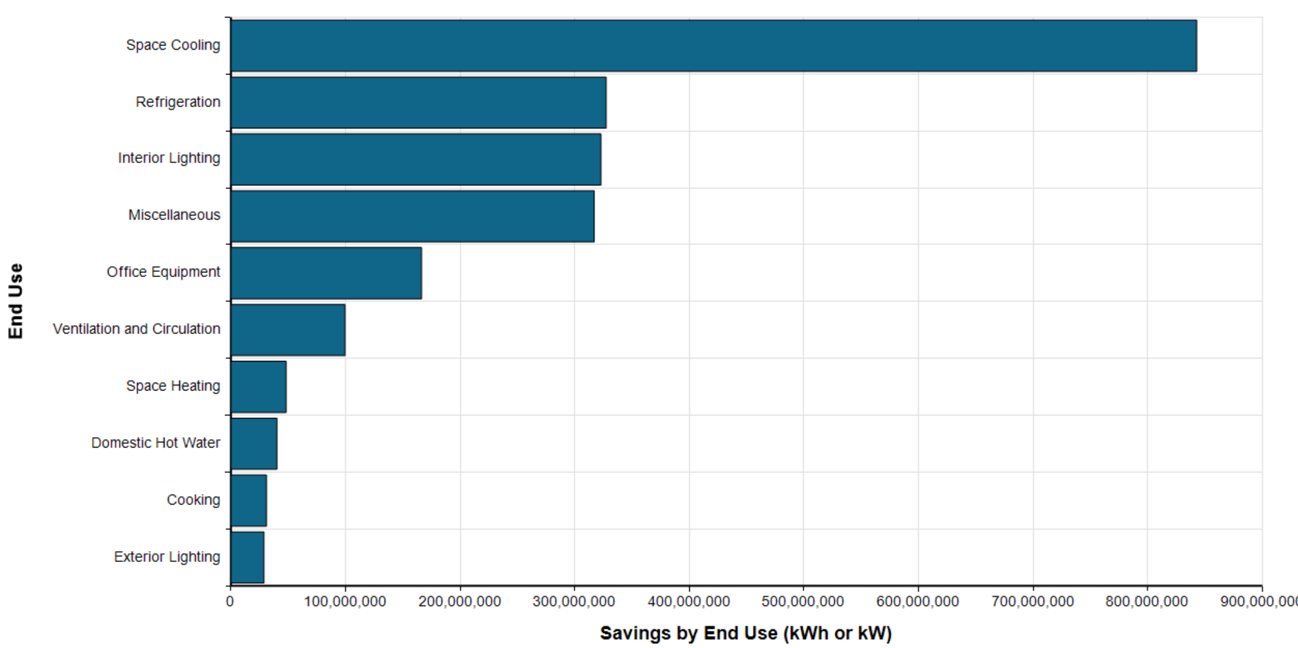


Figure 5-9 provides a summary of DEP energy efficiency technical potential contributions by commercial facility types analyzed in this study.

Figure 5-9: DEP Commercial EE Technical Potential by Segment

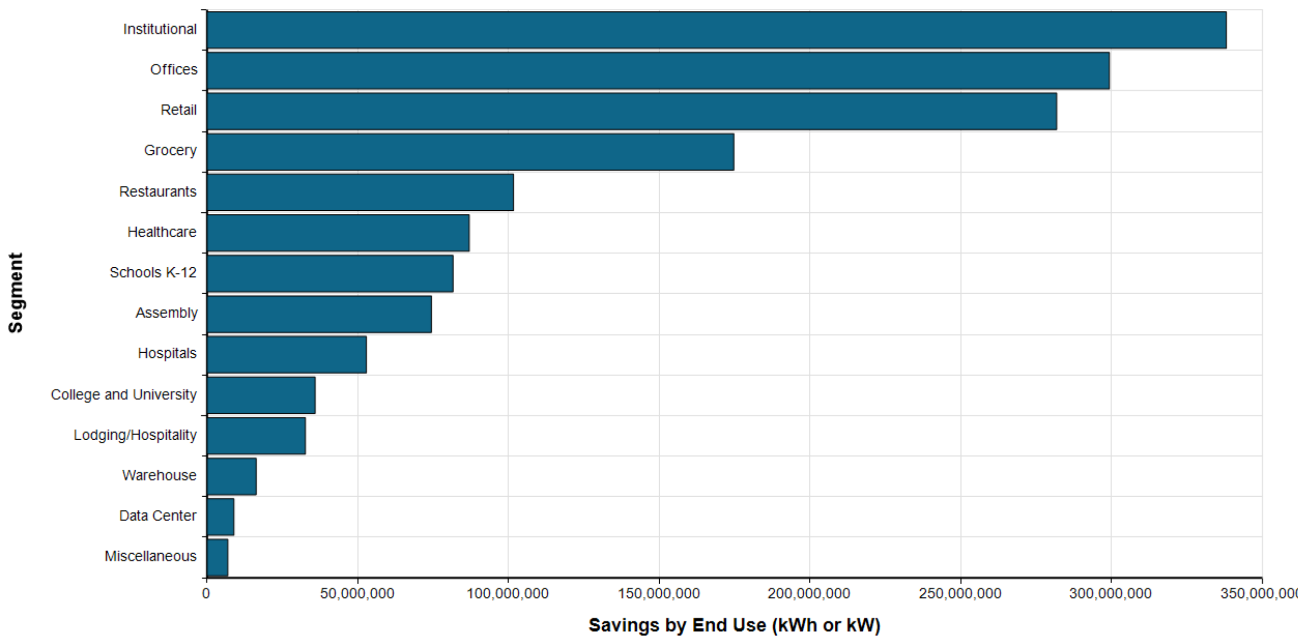


Figure 5-10 summarizes the DEP industrial sector energy efficiency technical potential by end use.

Figure 5-10: DEP Industrial EE Technical Potential – Cumulative 2047 by End-Use

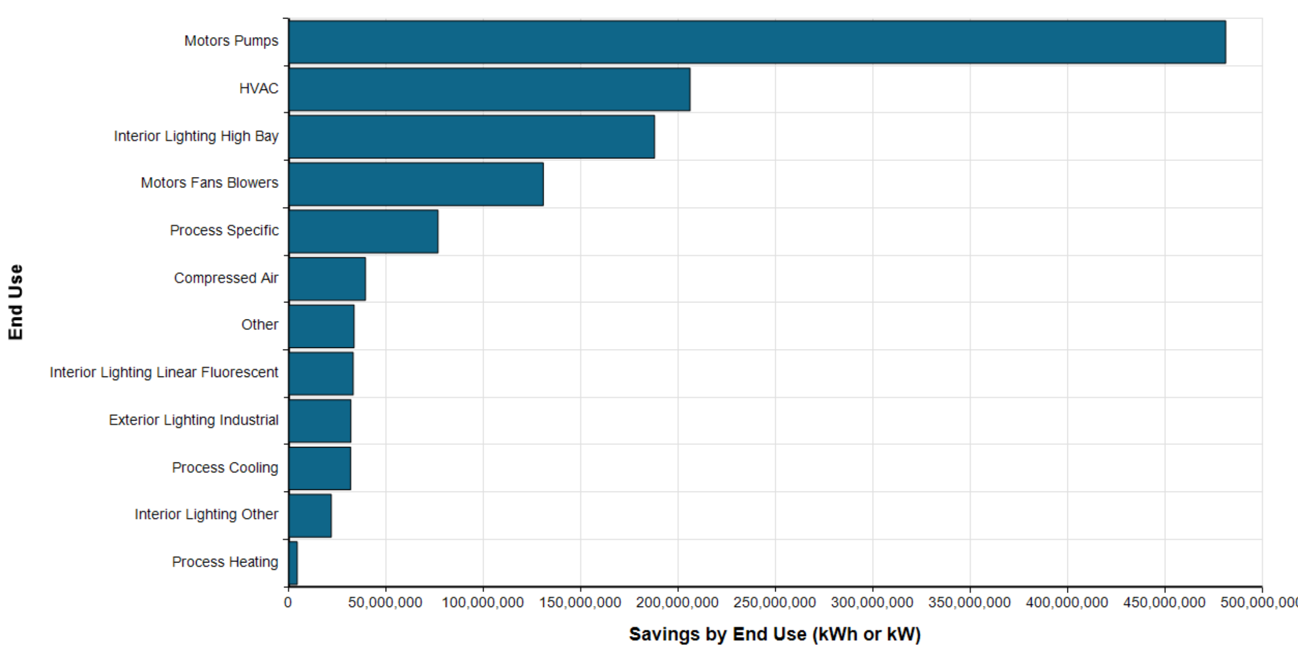
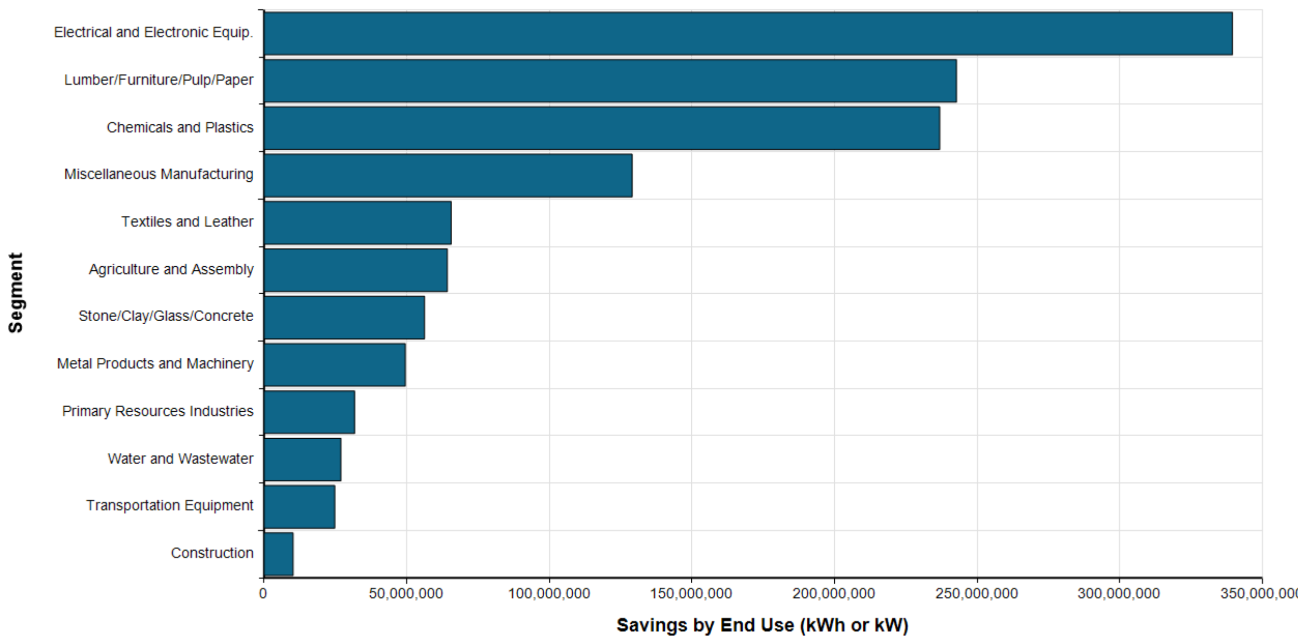


Figure 5-11 provides a summary of DEP energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 5-11: DEP Industrial EE Technical Potential by Segment



5.4. DEC Controllable Peak Load, by Customer Type

Technical potential for demand-side management is defined for each class of customers as follows:

- Residential & SMB customers – Technical potential is equal to the aggregate load for all end uses that can participate in Duke Energy's current and planned demand-side management programs in which the utility uses specialized devices to control loads (i.e., direct load control programs). This includes AC/heating loads for residential and SMB customers, and also water heater and pool pump loads for residential customers.
- Large C&I customers – Technical potential is equal to the total amount of load for each customer segment. This reflects the contractual nature of most large C&I programs and the fact that for a large enough payment and small enough number of events, we assume large C&I customers would be willing to reduce their usage to zero; technical potential includes all customers, even though many have opted out of the DSM rider and are therefore not actually eligible to participate in Duke Energy programs.

As with the EE analysis, DSM technical potential includes all customers, regardless of opt-out status or current participation in DSM programs. Table 5-3 summarizes the seasonal DSM technical potential by sector:

Table 5-3: DEC DSM Technical Potential by Sector[2]

Sector	Annual Technical Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	4,581.6	4,640.6
SMB	1,249.7	2,519.0
Large C&I	1,786.7	1,535.2
Total	7,618.0	8,694.8

5.4.1. Residential and SMB Customers

Residential technical potential is summarized in Table 5-4. The potential is broken down by end use and building type. A more detailed breakdown of the AC and heating loads by customer segment is provided in the economic potential section, along with the cost-effectiveness of each customer segment.

Table 5-4: DEC Residential DSM Technical Potential

Customer Segment	Season	End Use	# of Accounts	First Tertile		Second Tertile		Third Tertile		Total (Unadjusted)
				Residential		Residential		Residential		
				Avg. kw	Agg. MW	Avg. kw	Agg. MW	Avg. kw	Agg. MW	Agg. MW
Electric Heating	Summer	AC Cooling	1,196,613	1.71	680.7	2.18	870.5	2.66	1,062.1	2,613.3
	Winter	Heating	1,208,700	2.97	1,196.0	3.40	1,370.6	3.95	1,592.0	4,158.7
	Summer, Winter	Water Heater	829,168	0.37	102.8	0.37	102.8	0.37	102.8	308.4
	Summer	Pool Pump	48,348	0.22	3.5	0.22	3.5	0.22	3.5	10.4
Gas Heating	Summer	AC Cooling	673,095	1.71	382.9	2.18	489.7	2.66	597.4	1,470.0
	Winter	Heating	-	-	-	-	-	-	-	-
	Summer, Winter	Water Heater	466,407	0.37	57.8	0.37	57.8	0.37	57.8	173.5
	Summer	Pool Pump	27,196	0.22	2.0	0.22	2.0	0.22	2.0	5.9

* Based on NREL's end use load shapes[3]

[2] The potentials have excluded the kW reduction from existing participation.
[3] End-Use Load Profiles for the U.S. Building Stock. *The National Renewable Energy Laboratory (NREL)*. https://www.nrel.gov/buildings/end-use-load-profiles.html

Small and Medium Business technical potential is provided in Table 5-5, and RI removed existing participants from the customer base when calculating the technical potential.

Table 5-5: DEC SMB DSM Technical Potential

Segment	AC Cooling		Bring-your-own-kW	
	Avg. kw	Agg. MW	Avg. kw	Agg. MW
Assembly	7.27	199.54	7.10	220.55
College and University	11.18	18.01	14.42	23.35
Data Center	35.07	22.10	82.94	58.99
Grocery	10.41	32.67	15.49	55.61
Healthcare	9.39	68.73	21.14	174.78
Hospitals	19.46	13.89	162.87	129.48
Institutional	5.70	63.50	6.23	108.44
Lodging/Hospitality	42.39	148.25	63.89	243.95
Miscellaneous	2.44	10.70	2.13	16.83
Office	3.20	168.19	5.29	379.36
Restaurants	6.41	61.30	5.32	55.43
Retail	3.38	160.70	4.51	268.76
Schools K-12	17.10	99.76	41.19	248.01
Warehouse	24.11	37.10	7.78	48.46
Agriculture and Assembly	3.99	19.97	10.94	54.78
Chemicals and Plastics	12.33	12.20	25.38	25.10
Construction	3.27	35.76	5.67	61.98
Electrical and Electronic Equip.	0.55	0.97	7.59	13.36
Lumber/Furniture/Pulp/Paper	3.06	7.34	15.64	37.47
Metal Products and Machinery	7.83	20.40	30.50	79.48
Miscellaneous Manufacturing	5.30	17.51	8.17	27.01
Primary Resources Industries	0.04	0.13	0.49	1.44
Stone/Clay/Glass/Concrete	4.23	2.19	116.61	60.29
Textiles and Leather	18.80	18.42	93.04	91.13
Transportation Equipment	0.95	4.95	3.24	16.87
Water and Wastewater	0.77	5.46	2.54	18.09
Total (Adjusted)		**1,250**		**2,519**

5.4.2. Large C&I Customers

Table 5-6 provides the technical potential for C&I customers, broken down by industry type. Most of the technical potential provided by large C&I customers comes from the largest class of customers. The industries with the most technical potential are textiles and leather, data center, chemicals and plastics, and office. The potential is adjusted by removing average DR capacity that is provided by the Power Share program.

Table 5-6: DEC Large C&I DSM Technical Potential

Segment	Annual Technical Potential	
	Summer (Agg MW)	Winter (Agg MW)
Assembly	18.1	14.7
College and University	214.1	117.0
Data Center	367.7	348.6
Grocery	0.0	0.0
Healthcare	2.3	2.3
Hospitals	73.6	33.4
Institutional	18.0	10.7
Lodging/Hospitality	0.0	0.0
Miscellaneous	15.4	26.6
Office	67.8	63.7
Restaurants	0.0	0.0
Retail	6.3	4.4
Schools K-12	1.2	0.8
Warehouse	11.4	9.7
Agriculture and Assembly	0.0	0.0
Chemicals and Plastics	156.0	138.2
Construction	0.0	0.0
Electrical and Electronic Equip.	58.0	56.0
Lumber/Furniture/Pulp/Paper	86.0	86.6
Metal Products and Machinery	172.0	159.6
Miscellaneous Manufacturing	115.7	102.4
Primary Resources Industries	0.0	0.0
Stone/Clay/Glass/Concrete	74.7	67.4
Textiles and Leather	244.0	214.5
Transportation Equipment	65.2	60.1
Water and Wastewater	19.2	18.3
Total (Unadjusted)	**1,786.7**	**1,535.2**
Total (Adjusted)	**1,652.3**	**1,400.8**

5.5. DEP Controllable Peak Load, by Customer Type

Technical potential for demand-side management is defined for each class of customers as follows: Residential and SMB Customers, and Large C&I Customers. Technical potential for the non-residential customers includes all customers, regardless of opt-out status, even though opt-out customers are not eligible to participate in utility-sponsored DSM. Table 5-7 summarizes the seasonal DSM technical potential by sector[4]:

Table 5-7: DEP DSM Technical Potential by Sector[5]

Sector	Annual Technical Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	2,852	3,642
SMB	847	2,755
Large C&I	1,141	945
Total	**4,840**	**7,342**

5.5.1. Residential and SMB Customers

Residential technical potential is summarized in Table 5-8. The potential is broken down by end use and building type. A more detailed breakdown of the AC and heating loads by customer segment is provided in the economic potential section, along with the cost-effectiveness of each customer segment.

[4] The DSM technical potential has been adjusted to remove opted out customers and existing participants.
[5] These values are adjusted to remove capacity already enrolled in Duke Energy programs.

Table 5-8: DEP Residential DSM Technical Potential

Customer Segment	Season	End Use	First Tertile Residential		Second Tertile Residential		Third Tertile Residential		Total (Unadjusted)[6]
			Avg. kw	**Agg. MW**	**Avg. kw**	**Agg. MW**	**Avg. kw**	**Agg. MW**	**Agg. MW**
Electric Heating	Summer	AC Cooling	1.69	492.7	2.33	681.7	2.80	817.0	1,991.4
	Winter	Heating	3.21	948.5	3.55	1,048.4	4.41	1,301.2	3,298.1
	Summer/Winter	Water Heater*	0.40	80.9	0.40	80.9	0.40	80.9	242.7
	Summer	Pool Pump*	0.43	5.0	0.43	5.0	0.43	5.0	15.1
Gas Heating	Summer	AC Cooling	1.69	221.3	2.33	306.3	2.80	367.1	894.7
	Winter	Heating	-	-	-	-	-	-	-
	Summer/Winter	Water Heater*	0.40	36.4	0.40	36.4	0.40	36.4	109.1
	Summer	Pool Pump*	0.43	2.3	0.43	2.3	0.43	2.3	6.8

* Based on NREL's end use load shapes[7]

[6] The technical potential is adjusted later to remove existing capacity contributed by the Energy Wise Home Program.
[7] End-Use Load Profiles for the U.S. Building Stock. *The National Renewable Energy Laboratory (NREL)*. https://www.nrel.gov/buildings/end-use-load-profiles.html

Small and Medium Business technical potential is provided in Table 5-9, and RI removed existing participants from the customer base when calculating the technical potential. This estimate of technical potential includes customers that have opted out of DSM programs, even though they cannot ultimately participate in a Duke Energy sponsored program without modifying their opt-out status.

Table 5-9: DEP SMB DSM Technical Potential

Segment	AC Cooling		Heating	
	Avg. kw	Agg. MW	Avg. kw	Agg. MW
Assembly	5.55	44.10	13.87	142.38
College and University	29.83	15.93	85.08	45.44
Data Center	31.07	4.78	82.94	16.05
Grocery	26.62	34.04	88.67	149.82
Healthcare	4.79	14.63	19.83	76.48
Hospitals	18.34	7.00	32.86	15.41
Institutional	5.16	17.92	17.31	146.91
Lodging/Hospitality	9.97	44.60	16.46	87.02
Miscellaneous	9.28	2.87	23.18	22.89
Office	3.64	156.03	5.63	440.98
Restaurants	10.20	49.16	10.51	59.86
Retail	5.48	100.88	12.46	358.58
Schools K-12	24.56	50.00	67.46	145.97
Warehouse	8.43	3.10	2.44	14.37
Agriculture and Assembly	4.51	15.52	12.47	42.94
Chemicals and Plastics	29.97	7.37	233.94	57.56
Construction	2.76	8.72	11.19	35.36
Electrical and Electronic Equip.	8.10	207.83	19.49	499.91
Lumber/Furniture/Pulp/Paper	17.55	11.98	311.71	212.70
Metal Products and Machinery	36.35	13.99	95.86	36.89
Miscellaneous Manufacturing	0.00	0.00	35.45	24.45
Primary Resources Industries	3.43	5.67	8.04	13.31
Stone/Clay/Glass/Concrete	4.11	0.97	23.85	5.64
Textiles and Leather	69.66	17.29	252.52	62.66
Transportation Equipment	3.13	6.07	8.76	16.97
Water and Wastewater	1.28	6.50	4.74	24.04
Total (Adjusted)		**847**		**2,755**

5.5.2. Large C&I Customers

Table 5-10 provides the technical potential for C&I customers, broken down by industry type. Most of the technical potential provided by large C&I customers comes from the largest class of customers. The industries with the most technical potential are institutional and office. Technical potential includes all customers, regardless of opt-out status, but RI removed average DSM capacity that is provided by the Power Share program.

Table 5-10: DEP Large C&I DSM Technical Potential

Segment	Annual Technical Potential	
	Summer (Agg MW)	Winter (Agg MW)
Assembly	4.9	4.5
College and University	10.7	6.4
Data Center	7.7	7.0
Grocery	1.1	0.7
Healthcare	22.3	17.1
Hospitals	16.8	7.4
Institutional	260.7	223.0
Lodging/Hospitality	0.0	0.0
Miscellaneous	0.3	1.1
Office	21.8	20.1
Restaurants	0.0	0.0
Retail	7.0	5.3
Schools K-12	33.9	29.1
Warehouse	1.3	0.2
Agriculture and Assembly	10.0	8.8
Chemicals and Plastics	174.7	143.0
Construction	0.0	0.0
Electrical and Electronic Equip.	59.4	40.4
Lumber/Furniture/Pulp/Paper	148.9	113.5
Metal Products and Machinery	43.9	41.0
Miscellaneous Manufacturing	110.7	88.8
Primary Resources Industries	58.8	49.2
Stone/Clay/Glass/Concrete	49.9	45.6
Textiles and Leather	100.5	85.8
Transportation Equipment	7.0	7.2
Water and Wastewater	7.8	6.5
Total (Unadjusted)	**1,160.1**	**951.9**
Total (Adjusted)	**1,141.4**	**945.5**

6. Economic Potential

Economic potential compares the expected costs and benefits of energy and demand savings provided by EE and DSM measures and applies the utility cost test (UCT) to determine whether measures meet the scenario screening criterion of a benefit-cost ratio greater than 1. The economic potential is the sum of the energy savings associated with all measure permutations passing the economic screening.

The benefits of EE and DSM measures under the UCT test represent avoided utility costs that result from energy and demand savings. These include avoided energy generation costs, avoided transmission and distribution costs, and avoided costs associated with lower peak capacity demands. The DEC and DEP system is now a winter-planning system.

6.1. DSM Cost-Effective Screening Criteria

RI applied the UCT test in this study, as directed by Duke Energy and stakeholders. The UCT is calculated by comparing the total avoided electricity production and delivery costs of a measure to the cost of offering that measure in a utility-sponsored program. The utility cost is the cost of offering incentives and program administrative costs. UCT screening requires inputs for measure incentive rates and utility administrative costs. Resource Innovations used actual program cost data from Duke Energy's 2021 program cycle.

For EE screening, the UCT test is applied to each energy efficiency measure based on installation of the measure in the first year of the study (i.e., avoided cost benefits begin in year one and extend through the useful life of the measure; incremental costs are incurred in year one). By using DSMore outputs for lifetime avoided cost benefits, the screening aligns with Duke Energy's avoided cost forecast and allows for a direct comparison of measure costs with these avoided cost benefits. The screening included measures with a UCT ratio of 1.0 or higher for determining economic potential.

For this analysis, the non-incentive and incentive costs for each sector is detailed in Table 6-1. These values are based on the actual DSM program spending from Duke Energy and represent reasonable cost estimates in today's dollars with current technology. Economic potential screening is conducted using today's technology costs, and at this stage of the DSM analysis we have removed customers that have opted-out of the DSM rider since they are not included in the cost basis drawn from 2021 DSM program spending.

Table 6-1: Utility Costs

Sector	Unit	Season	Customer Recruitment			Annual Costs		
			Start-up Incentive	Equipment & Install	Other (Acquisition Marketing, etc)	Incentive	Other Cost	Maintenance Marketing
Residential	per customer	Summer AC	$0	$200	$2.5	$32	$17	$1.2
		Winter Heating	$0			$24		
SMB	per customer	Summer AC	$0	$200	$0	$64	$122	$0
	per kW	Winter Heating	$0	$0	$0	$30	$145	$0
Large C&I	per kW	Summer/Winter	$0	$0	$10	$42	$4.2	$0

The cost of enrolling customers from each customer segment is compared to the marginal benefits provided by enrolling customers in that segment. Because DSM programs are called relatively infrequently, very little benefit is derived from avoided energy costs to the point where they are insignificant. Instead, DSM derives its value from avoided generation capacity and avoided transmission and distribution capacity. RI also assumes an attrition rate of 7.5% annually with a measure life of 15 years.

Annual avoided capacity values were allocated between summer and winter using weights provided by Duke Energy. For DEC, 10% was allocated to summer and 90% to winter. For DEP, 100% of avoided costs are allocated to winter. Duke Energy indicated these changes were required by recent orders from the North Carolina Public Utilities Commission (NCPUC).

6.2. DEC Energy Efficiency Economic Potential

This section provides the results of the DEC energy efficiency economic potential for each of the three sectors.

6.2.1. Summary

Table 6-2 summarizes the DEC's cumulative energy efficiency economic potential by sector and levelized cost associated with the identified potential:

Table 6-2: DEC EE Economic Potential by Sector

Sector	Economic Potential (2023-2047)				
	Energy (GWh)	% of 2047 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	6,468	24%	1,481	1,313	$0.08
Commercial	2,924	12%	588	301	$0.04
Industrial	2,737	17%	367	366	$0.03
Total	**12,129**	18%	**2,436**	**1,980**	**$0.05**

6.2.2. Sector Details

Figure 6-1 summarizes the DEC residential sector energy cumulative efficiency economic potential by end use.

Figure 6-1: DEC Residential EE Economic Potential – Cumulative 2047 by End-Use

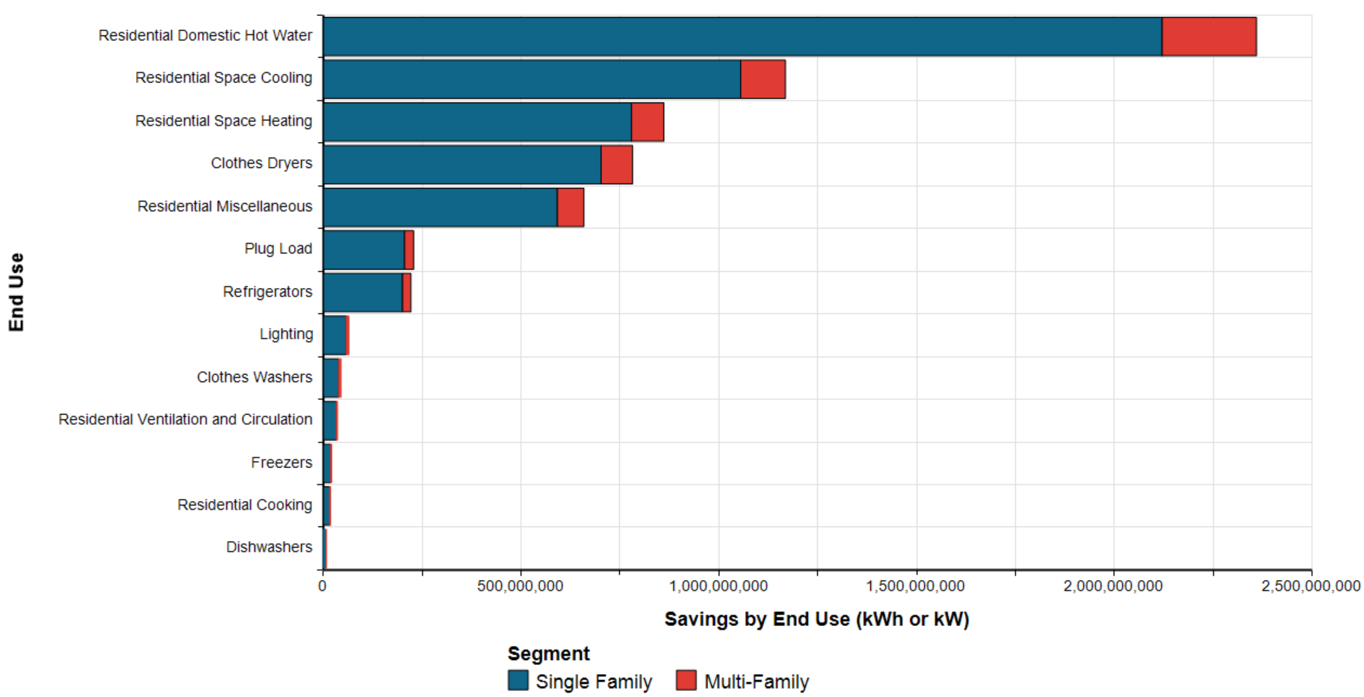


Figure 6-2 summarizes the DEC commercial sector EE economic potential by end use.

Figure 6-2: DEC Commercial EE Economic Potential – Cumulative 2047 by End-Use

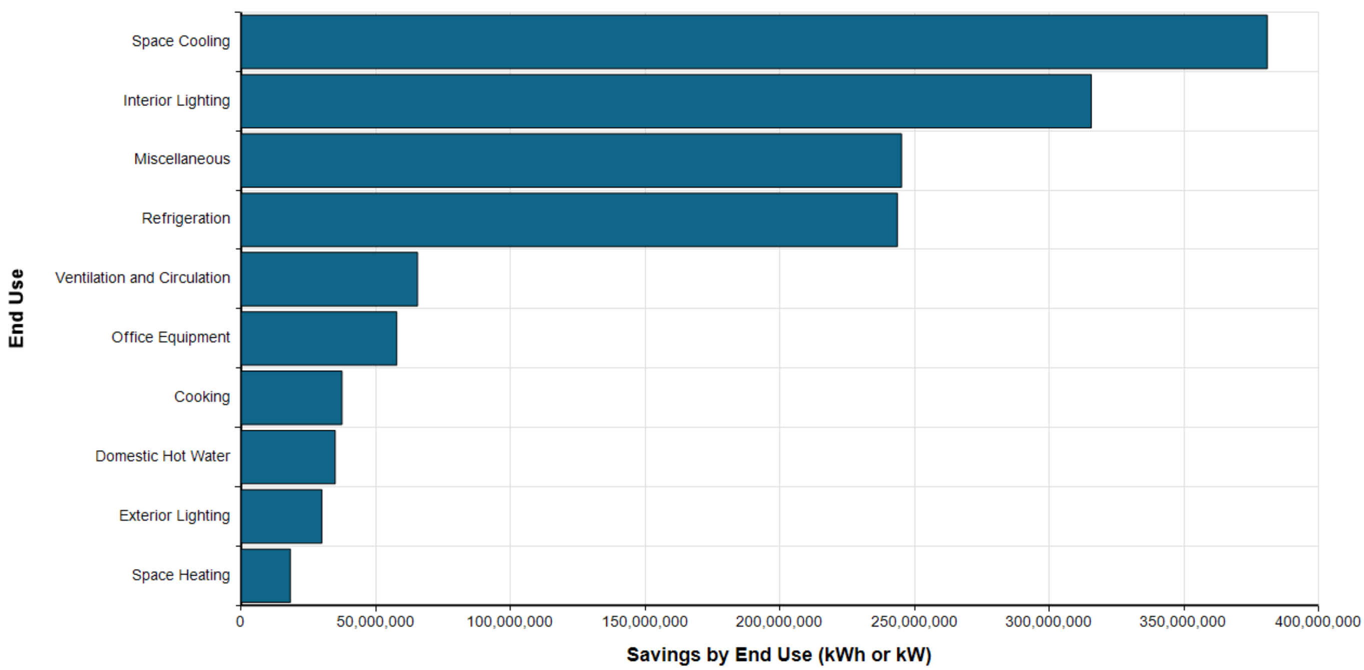


Figure 6-3 provides a summary of DEC energy efficiency economic potential contributions by commercial facility types analyzed in this study.

Figure 6-3: DEC Commercial EE Economic Potential – Cumulative 2047 by Segment

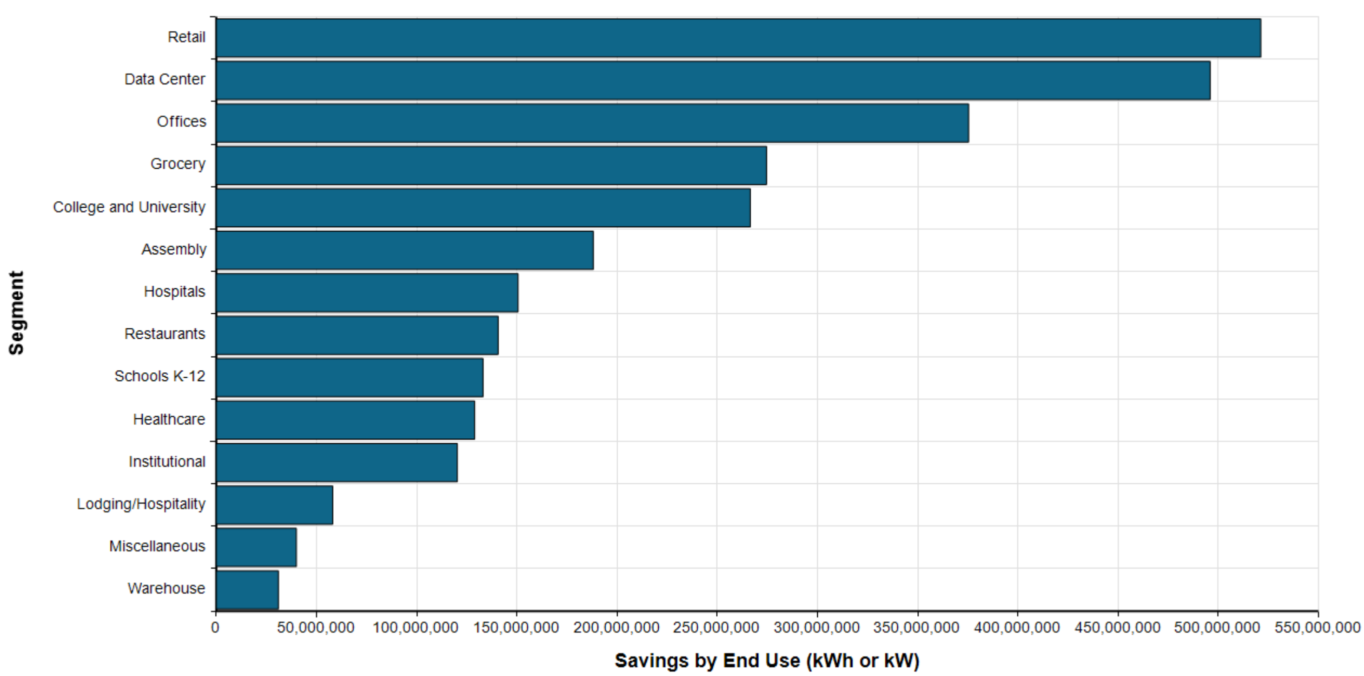


Figure 6-4 summarizes the DEC industrial sector energy efficiency economic potential by end use.

Figure 6-4: DEC Industrial EE Economic Potential – Cumulative 2047 by End-Use

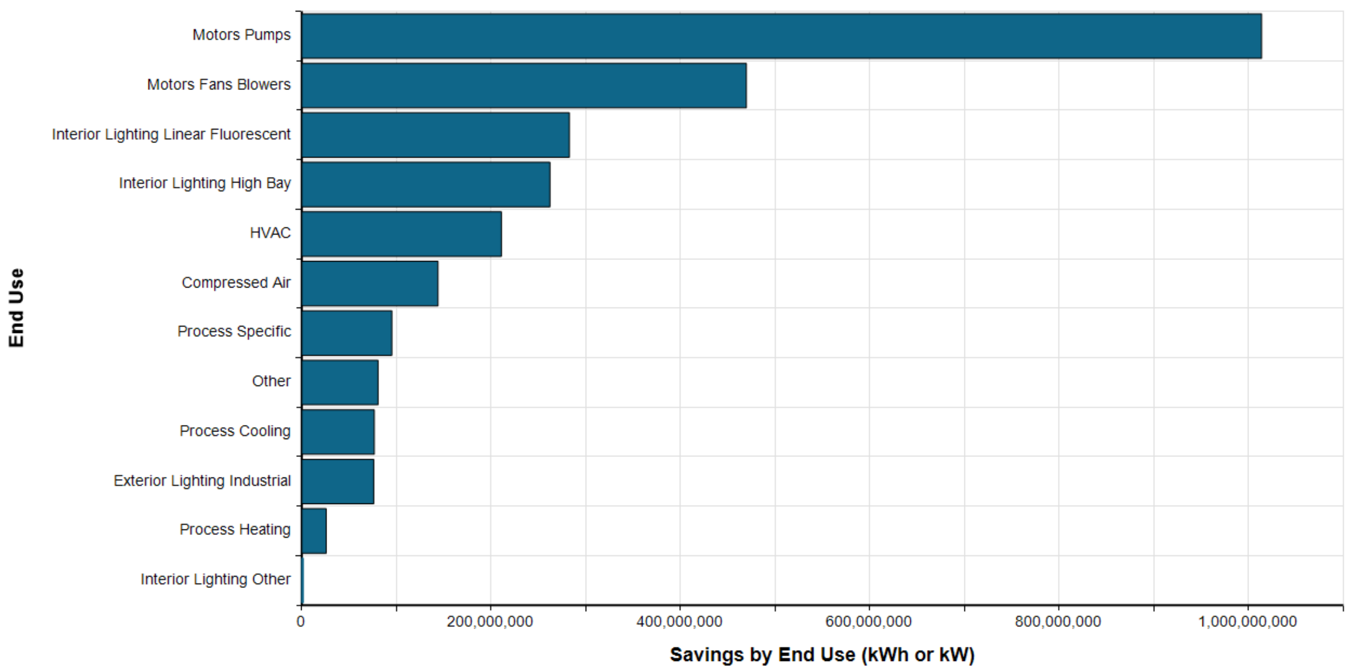
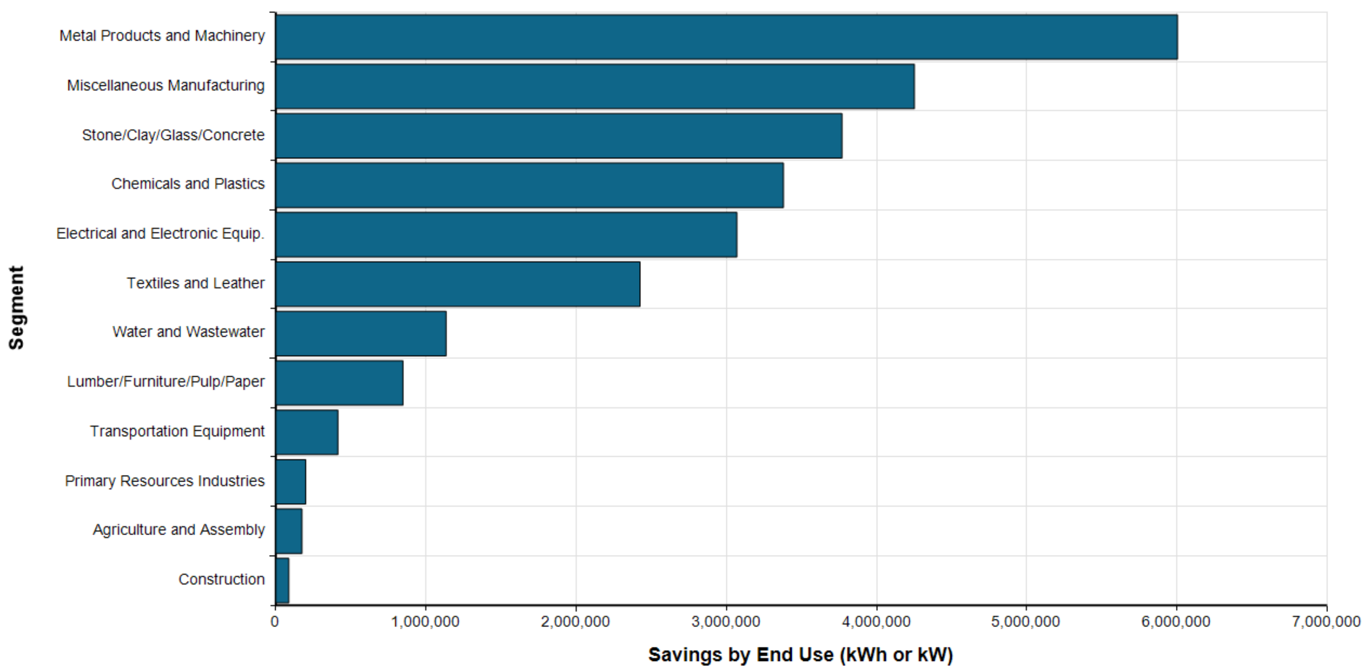


Figure 6-5 provides a summary of DEC energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 6-5: DEC Industrial EE Economic Potential by Segment



6.3. DEP Energy Efficiency Economic Potential

This section provides the results of the DEP energy efficiency economic potential for each of the three sectors.

6.3.1. Summary

Table 6-3 summarizes the DEP energy efficiency cumulative economic potential by sector and levelized cost associated with the identified potential:

Table 6-3: DEP EE Economic Potential by Sector

Sector	Economic Potential (2023-2047)				
	Energy (GWh)	% of 2047 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	4,761	24%	1,059	1,115	$0.08
Commercial	1,591	12%	286	175	$0.03
Industrial	1,043	12%	138	137	$0.02
Total	**7,396**	18%	**1,483**	**1,427**	$0.05

6.3.2. Sector Details

Figure 6-6 summarizes the DEP residential sector energy efficiency economic potential by end use.

Figure 6-6: DEP Residential EE Economic Potential – Cumulative 2047 by End- Use

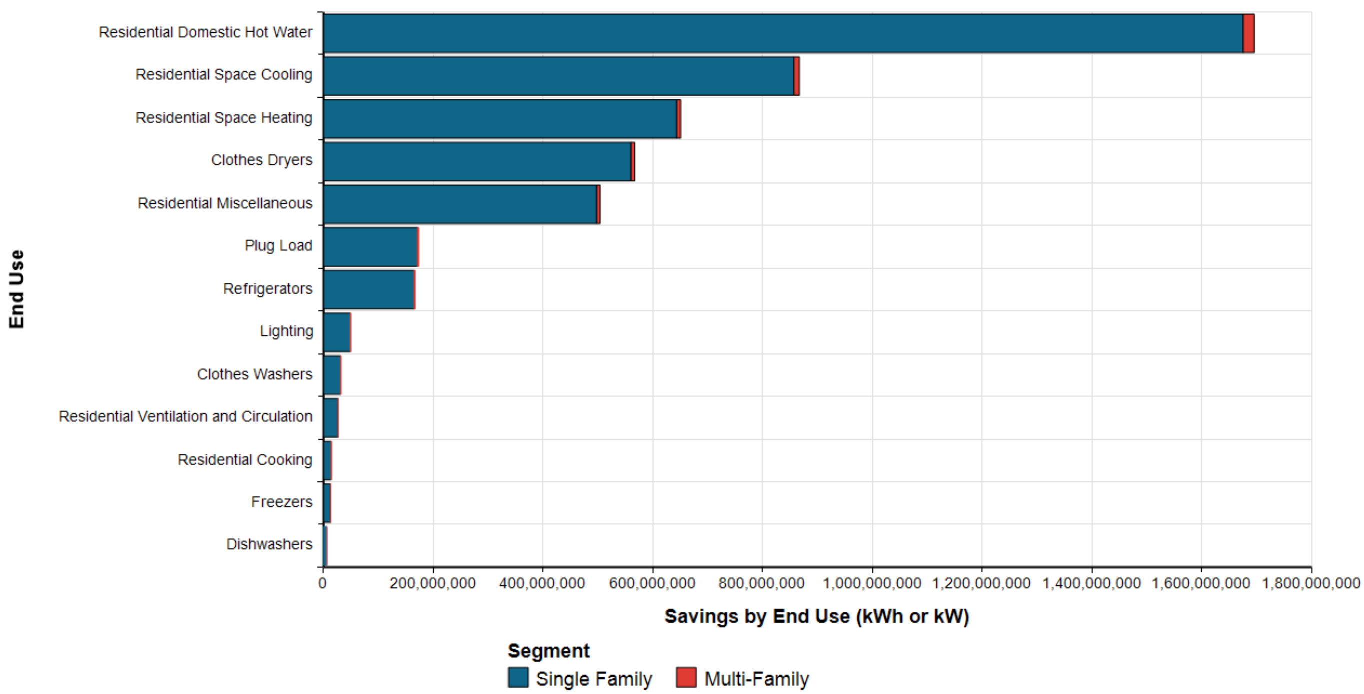


Figure 6-7 summarizes the DEP commercial sector energy efficiency economic potential by end use.

Figure 6-7: DEP Commercial EE Economic Potential – Cumulative 2047 by End-Use

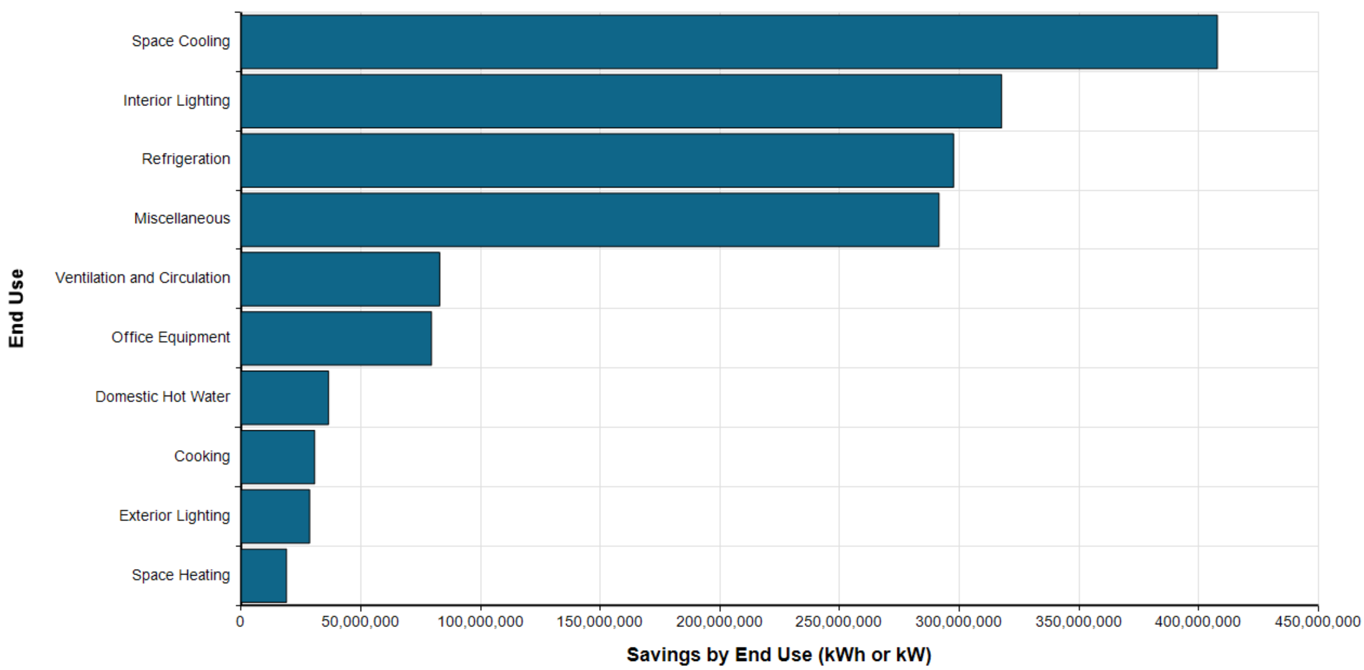


Figure 6-8 provides a summary of energy efficiency economic potential contributions by commercial facility types analyzed in this study.

Figure 6-8: DEP Commercial EE Economic Potential by Segment

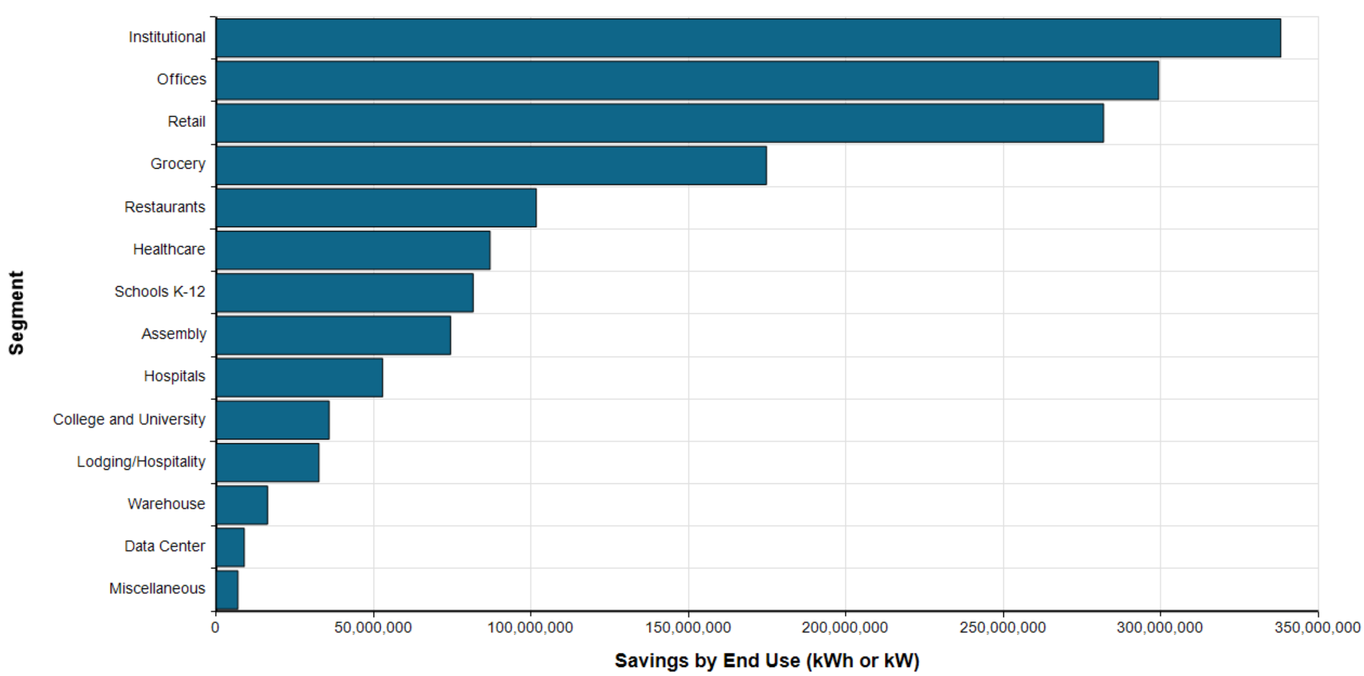


Figure 6-9 summarizes the DEP industrial sector energy efficiency economic potential by end use.

Figure 6-9: DEP Industrial EE Economic Potential – Cumulative 2047 by End-Use

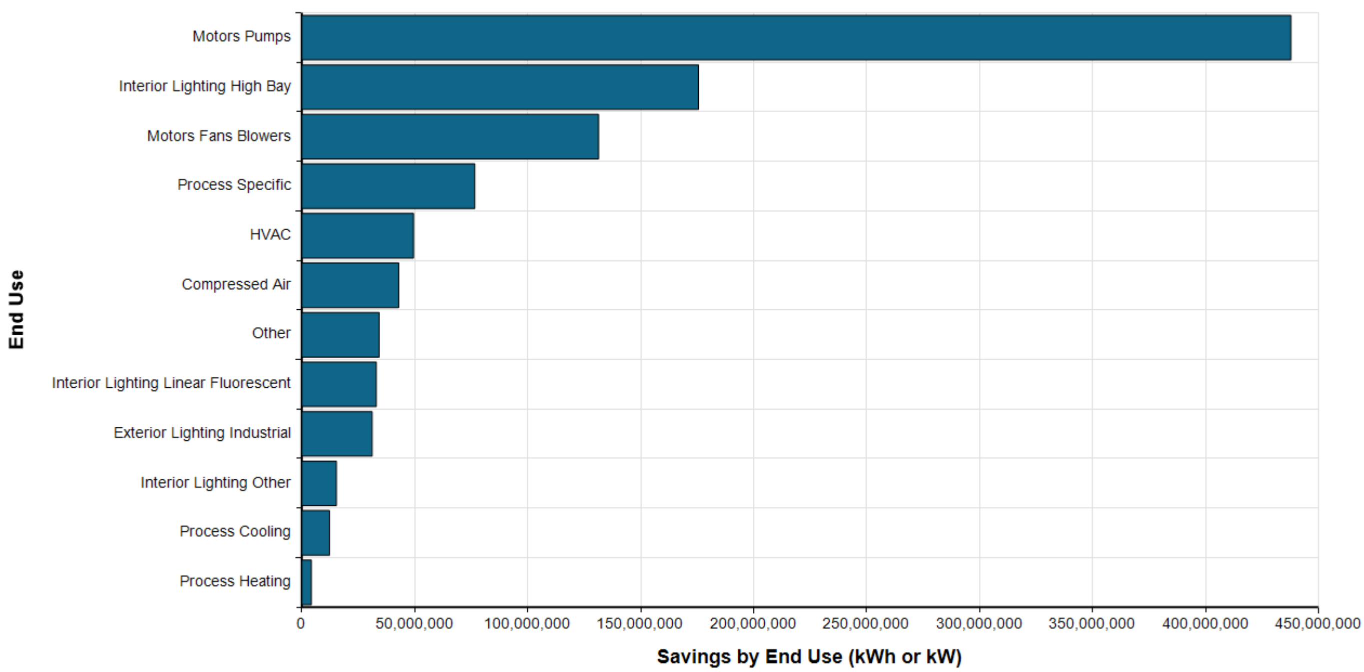
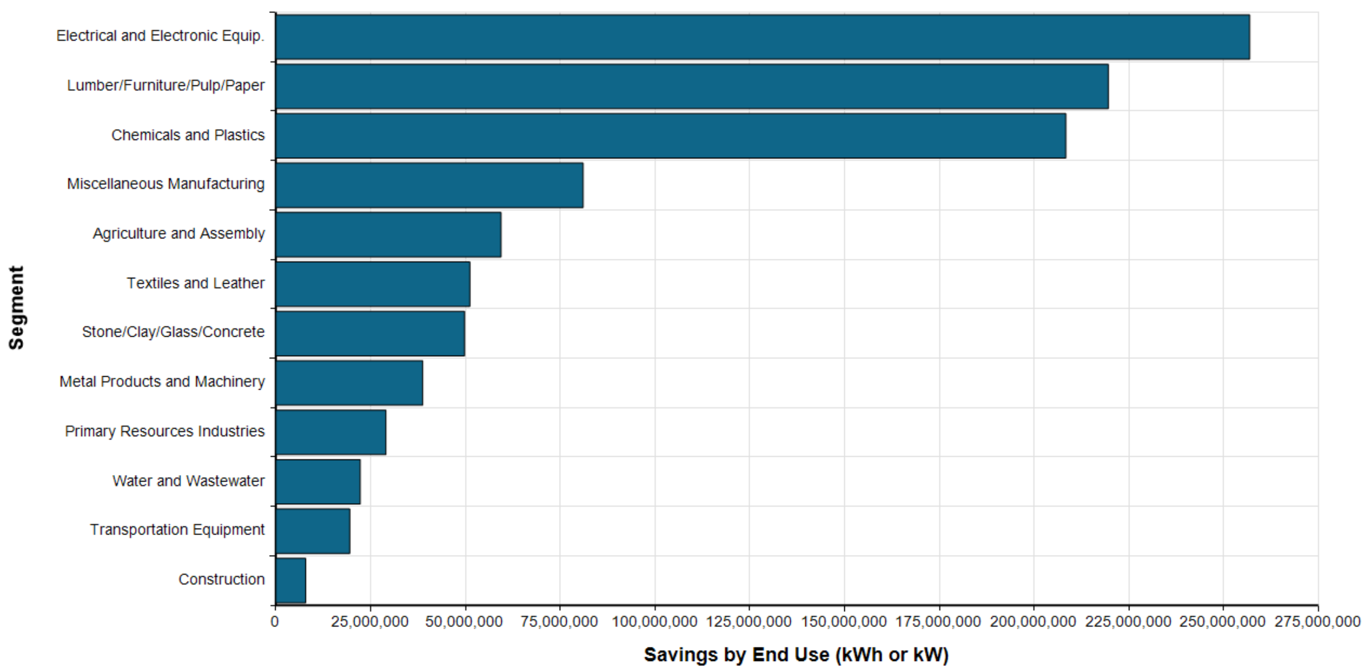


Figure 6-10 provides a summary of DEP energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 6-10: DEP Industrial EE Economic Potential by Segment



6.4. DEC Demand-side Management Economic Potential

DSM cost-effectiveness screening for economic potential determines whether the benefits of enrolling a marginal customer for a given customer segment into a demand-side management program will outweigh the costs. This study uses UCT as screening criteria that considers program administrative and incentive costs. Since economic potential ignores the participation rate in the program (this is taken into account when determining the achievable potential), cost-effectiveness screening at this point only considers whether a marginal customer for a given customer segment is worth pursuing for participation in the program.

Cost effectiveness screening for economic potential revealed that the vast majority of the technical potential presented in the prior chapter is cost-effective on a marginal basis, but the overall magnitude for SMB and Large C&I drops significantly after removing customers that have opted out of the DSM rider. These customers are not eligible to participate, and program costs may be shaped by recruiting customer from the remaining eligible customer population. Summary results for the economic potential for DEC are presented in Table 6-4.

Table 6-4: DEC DSM Economic Potential by Sector

Sector	Annual Economic Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	3,074	4,299
SMB	1,114	2,144
Large C&I	114	79
Total	**4,302**	**6,522**

Results for residential customer segments are presented in Table 6-5. Note that each of the three residential customer segments has a positive marginal net benefit, indicating that customers of each segment provide more benefit in the form of generation, transmission, and distribution capacity than they cost to enroll in the program and enable for load reduction. The benefit gas customers produce from their summer CAC load reductions are not cost-effective, but all-electric customers can be cost-effectively recruited to provide benefits in either season on the basis of winter avoided cost savings. The benefit from electric customers is weighted by their contribution in winter versus summer.

Table 6-5 presents the aggregate capacity each customer segment would be able to provide during summer and winter peaks, along with the benefits associated with that capacity, based on avoided generation and T&D costs. The total cost of enrolling customers in that segment is also presented. The net benefits and net benefits per customer are presented on the right side of the table.

Table 6-5: DEC Residential Economic DSM Potential Results

Segmentation	Usage Bin	Residential		Summer		Winter		Total Aggregate Net Benefit ($M)	Total Net Benefit per Customer ($)
		# of Accounts	Total Cost ($M)	Agg. MW	Total Benefit ($M)	Agg. MW	Total Benefit ($M)		
Electric Heating	1	398,871	$305	680.7	$79	1,196.0	$1,243	$1,017	$2,537
	2	398,871	$305	870.5	$101	1,370.6	$1,425	$1,220	$3,047
	3	398,871	$305	1,062.1	$123	1,592.0	$1,655	$1,473	$3,680
Gas Heating	1	224,365	$114	382.9	($70)	-	-	($70)	($0)
	2	224,365	$114	489.7	($57)	-	-	($57)	($0)
	3	224,365	$114	597.4	($45)	-	-	($45)	($0)
Dual Season HVAC DR Capacity				2,613.3		4,158.7			
Additional Potential from WH and PP				498.2		481.9			
Total Seasonal Potential (Unadjusted)				3,111.6		4,640.6			
Total Seasonal Potential (Adjusted for Existing DR)				3,073.6		4,298.6			

Similar tables, Table 6-6 and Table 6-7, are presented for SMB and large C&I customers. The majority of these customer segments produced a positive marginal net benefit, indicating that there is substantial, cost-effective DSM potential available in DEC's territory.

Table 6-6: DEC SMB Economic Potential Results

SMB	Summer				Winter			
Segment	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)
Assembly	195.8	$5.0	$226	$8,233	216.3	$40.3	$250	$6,895
College and University	11.0	$0.2	$13	$11,296	14.9	$2.8	$17	$12,938
Data Center	19.3	$0.1	$22	$40,312	51.5	$9.6	$59	$80,321
Grocery	21.9	$0.5	$25	$9,891	20.8	$3.9	$24	$7,002
Healthcare	65.4	$1.3	$76	$10,662	166.3	$31.0	$192	$20,473
Hospitals	5.5	$0.1	$6	$10,930	115.1	$21.5	$133	$174,394
Institutional	60.0	$2.1	$69	$6,110	90.6	$16.9	$105	$5,104
Lodging/Hospitality	147.5	$0.6	$170	$48,761	242.8	$45.2	$280	$61,873
Miscellaneous	10.6	$0.8	$12	$2,626	16.7	$3.1	$19	$2,063
Office	158.3	$9.5	$183	$3,386	330.2	$61.5	$381	$4,581
Restaurants	59.2	$1.7	$68	$7,216	53.6	$10.0	$62	$5,152
Retail	141.7	$8.6	$164	$3,366	248.5	$46.3	$287	$4,174
Schools K-12	59.1	$0.9	$68	$14,655	144.2	$26.9	$167	$29,411
Warehouse	36.2	$0.3	$42	$27,657	47.3	$8.8	$55	$7,534
Agriculture and Assembly	19.4	$0.9	$22	$4,420	53.2	$9.9	$61	$10,595
Chemicals and Plastics	8.5	$0.1	$10	$12,549	12.4	$2.3	$14	$15,572
Construction	35.3	$2.0	$41	$3,594	58.1	$10.8	$67	$5,220
Electrical and Electronic Equip.	0.9	$0.3	$1	$447	13.1	$2.4	$15	$7,350
Lumber/Furniture/Pulp/Paper	4.3	$0.4	$5	$2,218	27.2	$5.1	$31	$12,754
Metal Products and Machinery	13.0	$0.4	$15	$6,449	59.4	$11.1	$69	$25,489
Miscellaneous Manufacturing	14.8	$0.6	$17	$5,277	25.8	$4.8	$30	$7,999
Primary Resources Industries	0.7	$0.5	$1	$75	1.3	$0.2	$2	$436
Stone/Clay/Glass/Concrete	3.1	$0.1	$4	$8,909	42.1	$7.8	$49	$102,547
Textiles and Leather	13.0	$0.1	$15	$18,787	63.5	$11.8	$73	$77,523
Transportation Equipment	4.6	$0.9	$5	$874	13.4	$2.5	$15	$2,557
Water and Wastewater	5.5	$1.3	$6	$709	16.2	$3.0	$19	$2,237
Total EP (Adjusted)	**1,114**				**2,144**			

Table 6-7: DEC Large C&I Economic Potential Results

Large C&I		Total Benefits			Annual Economic Potential	
Segment	# of Accounts	Total Cost ($M)	Total Benefits ($M)	Total Net Benefit per Customer	Summer Agg MW	Winter Agg MW
Assembly	1	$0.45	$1.77	$1,313,445	1.5	1.7
College and University	-	$0.00	$0.00	$0	-	-
Data Center	4	$15.98	$62.12	$11,536,134	53.8	34.5
Grocery	-	$0.00	$0.00	$0	-	-
Healthcare	-	$0.00	$0.00	$0	-	-
Hospitals	-	$0.00	$0.00	$0	-	-
Institutional	-	$0.00	$0.00	$0	-	-
Lodging/Hospitality	-	$0.00	$0.00	$0	-	-
Miscellaneous	4	$3.84	$14.93	$2,772,714	12.9	21.8
Office	5	$7.03	$27.32	$4,058,813	23.7	19.3
Restaurants	-	$0.00	$0.00	$0	-	-
Retail	1	$0.04	$0.15	$112,885	0.1	0.6
Schools K-12	1	$0.36	$1.42	$1,053,021	1.2	0.8
Warehouse	-	$0.00	$0.00	$0	-	-
Agriculture and Assembly	-	$0.00	$0.00	$0	-	-
Chemicals and Plastics	7	$12.17	$47.30	$5,019,714	41.0	31.7
Construction	-	$0.00	$0.00	$0	-	-
Electrical and Electronic Equip.	1	$0.35	$1.37	$1,021,111	1.2	1.4
Lumber/Furniture/Pulp/Paper	5	$2.25	$8.73	$1,297,662	7.6	13.3
Metal Products and Machinery	2	$1.76	$6.83	$2,534,892	5.9	6.1
Miscellaneous Manufacturing	4	$3.11	$12.10	$2,246,272	10.5	7.0
Primary Resources Industries	-	$0.00	$0.00	$0	-	-
Stone/Clay/Glass/Concrete	1	$1.64	$6.37	$4,729,843	5.5	5.1
Textiles and Leather	6	$23.24	$90.35	$11,185,093	78.2	66.6
Transportation Equipment	1	$0.90	$3.51	$2,604,622	3.0	2.0
Water and Wastewater	2	$0.61	$2.38	$883,179	2.1	1.9
Total EP (Unadjusted)					248.2	213.8
Total EP (Adjusted)					113.8	79.4

6.5. DEP Demand-side Management Economic Potential

Cost effectiveness screening for economic potential revealed that the vast majority of the technical potential presented in the prior chapter is cost-effective on a marginal basis, but the overall magnitude for SMB and Large C&I drops significantly after removing customers that have opted out of the DSM rider. These customers are not eligible to participate, and program costs may be shaped by recruiting customer from the remaining eligible customer population. Summary results for the economic potential for DEP are presented in Table 6-8.

Table 6-8: DEP DSM Economic Potential by Sector

Sector	Annual Economic Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	2,320	3,034
SMB	778	1,860
Large C&I	10	16
Total	**3,108**	**4,910**

Results for residential customer segments are presented in Table 6-9. Note that all electric heating customers have a positive marginal net benefit, indicating that customers of each segment provide more benefit in the form of generation, transmission, and distribution capacity than they cost to enroll in the program and enable for load reduction.

This table presents the aggregate capacity each customer segment would be able to provide during summer and winter peaks, along with the benefits associated with that capacity, based on avoided generation and T&D costs. The total cost of enrolling customers in that segment is also presented. The net benefits and net benefits per customer are presented on the right side of the table.

Table 6-9: DEP Residential Economic Potential Results

Segmentation	Usage Bin	Residential		Summer		Winter		Total Aggregate Net Benefit ($M)	Total Net Benefit per Customer ($)
		# of Accounts	Total Cost ($M)	Agg. MW	Total Benefit ($M)	Agg. MW	Total Benefit ($M)		
Electric Heating	1	292,218	$273	492.7	$0	948.5	$1,081	$808	$2,764
	2	292,218	$273	681.7	$0	1,048.4	$1,194	$922	$3,154
	3	292,218	$273	817.0	$0	1,301.2	$1,482	$1,210	$4,139
Gas Heating	1	131,287	$78	221.3	$0	-	$0	($78)	($595)
	2	131,287	$78	306.3	$0	-	$0	($78)	($595)
	3	131,287	$78	367.1	$0	-	$0	($78)	($595)
Dual Season HVAC DR Capacity				1,991.4		3,298.1			
Additional Seasonal Potential from WH and PP				373.7		141.4			
Total Seasonal Potential (Unadjusted)				2,365.2		3,439.6			
Total Seasonal Potential (Adjusted for Existing DR)				2,320.1		3,033.5			

Similar tables, Table 6-10 and Table 6-11, are presented for SMB and large C&I customers. The majority of these customer segments evaluated produced a positive marginal net benefit, indicating that there is substantial cost-effective DSM potential available in DEP's territory.

Table 6-10: DEP SMB Economic Potential Results

SMB	Summer				Winter			
Segment	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)
Assembly	43.7	$18.4	$49.5	$3,492	104.3	$19.6	$118	$11,075
College and University	6.0	$0.8	$6.8	$15,649	22.2	$4.2	$25	$54,849
Data Center	5.3	$0.4	$6.0	$33,097	15.8	$3.0	$18	$87,829
Grocery	12.1	$2.6	$13.7	$8,948	18.8	$3.5	$21	$14,274
Healthcare	22.0	$6.8	$24.9	$5,515	55.7	$10.4	$63	$16,033
Hospitals	8.7	$0.7	$9.8	$27,045	17.7	$3.3	$20	$49,657
Institutional	12.2	$11.0	$13.8	$526	92.6	$17.4	$105	$16,438
Lodging/Hospitality	46.9	$10.0	$53.1	$8,902	80.6	$15.1	$91	$15,746
Miscellaneous	5.1	$1.1	$5.8	$8,431	22.8	$4.3	$26	$39,090
Office	197.8	$119.3	$223.9	$1,815	390.0	$73.1	$441	$6,394
Restaurants	53.2	$10.8	$60.2	$9,460	56.5	$10.6	$64	$10,213
Retail	93.4	$47.3	$105.7	$2,558	245.2	$46.0	$277	$10,140
Schools K-12	46.7	$3.7	$52.8	$27,738	101.9	$19.1	$115	$54,316
Warehouse	12.4	$3.0	$14.0	$7,467	24.5	$4.6	$28	$15,752
Agriculture and Assembly	12.9	$7.0	$14.6	$2,247	18.1	$3.4	$21	$5,071
Chemicals and Plastics	0.5	$0.3	$0.6	$2,132	4.2	$0.8	$5	$29,766
Construction	2.0	$6.5	$2.2	($1,358)	14.4	$2.7	$16	$4,325
Electrical and Electronic Equip.	171.2	$52.0	$193.7	$5,644	389.5	$73.0	$441	$14,647
Lumber/Furniture/Pulp/Paper	6.5	$1.0	$7.3	$13,319	119.1	$22.3	$135	$235,987
Metal Products and Machinery	6.6	$0.6	$7.4	$23,102	13.7	$2.6	$15	$43,686
Miscellaneous Manufacturing	-	$1.1	$0.0	($2,071)	15.0	$2.8	$17	$26,471
Primary Resources Industries	10.8	$3.2	$12.3	$5,795	5.7	$1.1	$6	$3,437
Stone/Clay/Glass/Concrete	0.2	$0.3	$0.3	($30)	2.7	$0.5	$3	$18,500
Textiles and Leather	-	$0.4	$0.0	($2,071)	0.7	$0.1	$1	$3,995
Transportation Equipment	3.7	$3.9	$4.2	$140	4.6	$0.9	$5	$2,304
Water and Wastewater	3.1	$10.4	$3.5	($1,381)	23.7	$4.4	$27	$4,476
Total EP (Adjusted)	**778**				1,860			

Table 6-11: DEP Large C&I Economic Potential Results

Large C&I			Total Benefits		Annual Economic Potential	
Segment	# of Accounts	Total Cost ($M)	Total Benefits ($M)	Total Net Benefit per Customer	Summer Agg MW	Winter Agg MW
Assembly	1	$0.72	$1.42	$701,509	1.1	1.3
College and University	-	$0.00	$0.00	$0	-	-
Data Center	1	$0.18	$0.35	$175,285	0.3	0.3
Grocery	-	$0.00	$0.00	$0	-	-
Healthcare	-	$0.00	$0.00	$0	-	-
Hospitals	-	$0.00	$0.00	$0	-	-
Institutional	5	$4.82	$9.52	$941,179	8.4	5.7
Lodging/Hospitality	-	$0.00	$0.00	$0	-	-
Miscellaneous	-	$0.00	$0.00	$0	-	-
Office	5	$3.22	$6.37	$629,539	5.6	5.3
Restaurants	-	$0.00	$0.00	$0	-	-
Retail	2	$1.29	$2.55	$630,914	2.3	0.7
Schools K-12	-	$0.00	$0.00	$0	-	-
Warehouse	1	$0.73	$1.44	$709,940	1.3	0.2
Agriculture and Assembly	-	$0.00	$0.00	$0	-	-
Chemicals and Plastics	1	$0.73	$1.44	$711,643	1.3	1.0
Construction	-	$0.00	$0.00	$0	-	-
Electrical and Electronic Equip.	2	$1.30	$2.56	$632,625	2.3	0.5
Lumber/Furniture/Pulp/Paper	-	$0.00	$0.00	$0	-	-
Metal Products and Machinery	3	$2.11	$4.16	$685,431	3.0	3.7
Miscellaneous Manufacturing	3	$1.99	$3.94	$648,348	3.5	3.2
Primary Resources Industries	-	$0.00	$0.00	$0	-	-
Stone/Clay/Glass/Concrete	-	$0.00	$0.00	$0	-	-
Textiles and Leather	-	$0.00	$0.00	$0	-	-
Transportation Equipment	-	$0.00	$0.00	$0	-	-
Water and Wastewater	-	$0.00	$0.00	$0	-	-
Total EP (Unadjusted)					29.0	21.9
Total EP (Adjusted)					10.4	15.6

7. Achievable Market Potential

Achievable market potential estimates customer adoption rates for cost-effective measures in a market featuring utility-sponsored programs. In this MPS we responded to feedback from Duke Energy and the Carolinas EE/DSM Collaborative by developing customer adoption rates that are independent of historic Duke Energy program participation trends. We calibrated start year adoptions to 2021 Duke Energy program performance, but future adoption of measures cost-effectively offered by Duke Energy programs is driven by customer payback. Customer payback describes the number of years required for a customer to save an amount of energy equal to measure first costs (fewer incentive payments from utility programs). Utility-sponsored programs are typically focused on addressing market barriers and thereby boosting customer adoption of energy efficiency.

Customers may forego cost-effective EE and DSM for a variety of reasons, some of which may include customer preferences for benefits arising from other types of investments; time and effort required to engage with program administration or satisfy program requirements; high initial costs, lack of time to identify, evaluate, acquire, and install new measures, long investment payback times, payback uncertainty, or even for the inconvenience. Customers may need to overcome non-economic barriers such as: lack of knowledge about electricity consumption and associated technology; principal-agent issues, a.k.a. “split incentive,” problems; inability to capture non-market benefits; or economic conditions that potentially limit availability of some measures, increases measure costs, or affects customers’ incomes. In addition to these economic tradeoffs and market barriers, economic research increasingly demonstrates the strong role that human behavior plays in affecting purchase decisions.

The EE/DSM program lifecycle is designed explicitly to address the need for adaptive management of utility programs and continuously improve upon programs’ ability to effectively confront market barriers. It also engages stakeholders to collaborate with utilities around program iterations and offer ideas from outside perspectives. The scope of this MPS does not include program design, as Duke Energy has been offering EE and DSM programs for over a decade and has consistently followed the adaptive management principles of the EE/DSM program lifecycle: market assessment, program design, program implementation, program evaluation, and adaptation. This study represents the market assessment component of this adaptive management cycle.

7.1. Customer Adoption Assumptions

Describing the magnitude and degree of influence exerted by market barriers is not easily addressed in a quantitative manner, as attested by industry research. Market adoption estimates have been derived from econometric analysis of historic data, and researchers suggest the results may imply the presence of market barriers or reflect lower customer demand than projections from benefit-cost analysis.

7.1.1. Market Barriers and Program Strategies

We reviewed industry literature on market barriers, which has identified four broad categories of market barriers: economic or financial; regulatory, technical or informational; and, behavioral. Within each of these four categories exists a more detailed set of market barriers further describing the broader category. We drew on this background material and expanded with further literature and collective industry experience. The results of our analysis identified a set of utility-sponsored, program archetypes. Within each archetype we delineated specific tactics programs use to address each market barrier. We provided the results of our analysis to Duke Energy and the Carolinas EE/DSM Collaborative.

7.1.2. Duke Energy Program Experience

We used the results of the market barriers and program strategy analysis as a framework for reviewing Duke Energy EM&V reports. Volume II of our literature review identifies Duke Energy programs associated with each program archetype. We listed the program tactics used in each of Duke Energy's programs and associated them with the target market barrier they seek to address. We developed a brief description, drawn from EM&V results, for each program tactic as implemented by Duke Energy and reported. This review described Duke Energy program features such as deemed incentives, defined measures, awareness messaging, market actor engagement, streamlined participation process, and more as relevant to the program archetype. We also drew on collective market experience with program implementation to offer additional insight from the perspective of program implementors and offering designers.

The review used EM&V reports that were available at the time of this analysis in spring of 2022 and the reports themselves were from a variety of program vintages, depending on each program's position in the EE/DSM program lifecycle at the time of review. This review, as well as the preceding volume I were provided to Duke Energy and the Carolinas EE/DSM Collaborative in support of stakeholder engagement around how Duke Energy programmatic efforts to reduce market barriers might be addressed by assumptions in the MPS.

7.1.3. MPS Stakeholder Engagement

Resource Innovations developed these materials to solicit feedback from stakeholders, consisting of Duke Energy and the Carolinas EE/DSM Collaborative members. The materials offered background information that could serve as a common basis of material for participants and provide a reference for discussions about how Duke Energy is seeking to address market barriers with utility-sponsored programs. Duke Energy staff attended the discussion to provide their insight and direct experience working with the program in North Carolina. In volume II of the report, we offered suggested topics around each of Duke Energy's programs, and the materials were provided to participants ahead of the meeting. During the meeting itself the discussion followed participants' interests and questions around specific programs, drawing on the background materials, as time did not allow for exhaustive discussion of each program. Instead, we were able to provide a concise template to stakeholders and request specific recommendations for each program. We requested that stakeholders identify the Duke Energy program, target market barrier, and a description of the program features to which their suggestions applied. Appendix X contains the feedback template and EE/DSM Collaborative members' responses.

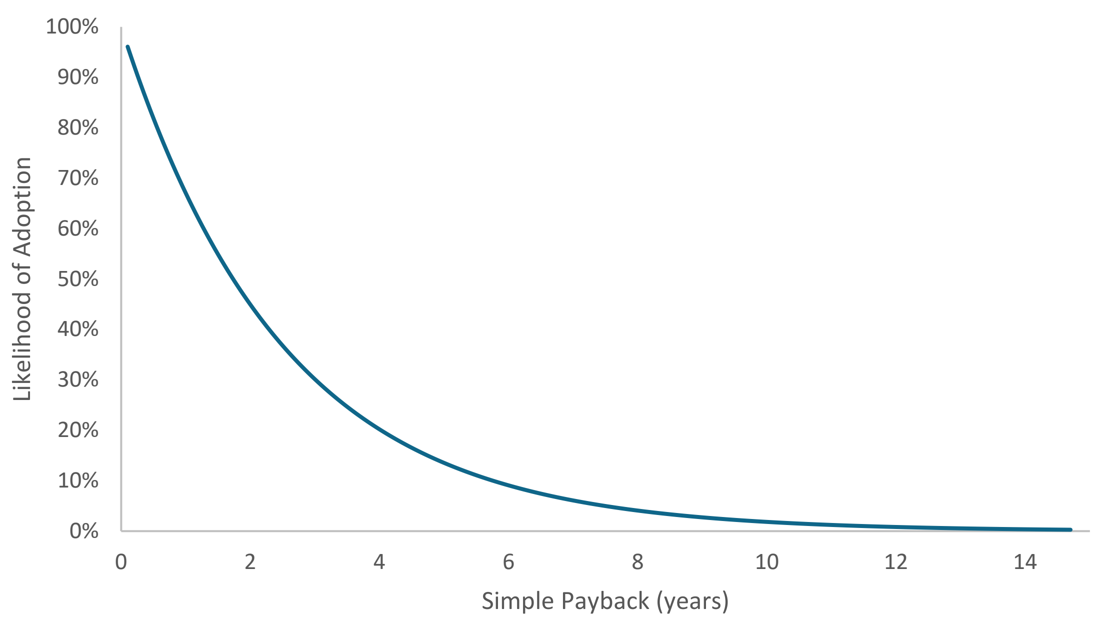
7.1.4. MPS Adoption Curves

The information we gained from literature reviews, the Carolinas EE/DSM Collaborative engagement, and Duke Energy indicates Duke Energy programs are efficaciously pursuing the EE/DSM lifecycle of market analysis, program design, program implementation, program evaluations, stakeholder engagement, and adaptation. As the result of the EE/DSM lifecycle process and the efforts of Duke Energy, stakeholders, and customers to erode market barriers, RI developed market adoption curves that reflect assumptions for higher customer adoption rates.

We apply customer payback acceptance curves to all cost-effective measures, which addresses one major market barrier: time preferences for money. Customers value immediate monetary savings much more than future savings, whether due to economic of behavioral factors. Additional barriers may exist, they may lead to lower-than-expected adoption rates, and payback acceptance curves may not fully describe the impacts of market barriers. The magnitude or degree of influence market barriers currently exert in the North Carolina service territory is not readily measured by existing data, though EM&V reports describe ongoing efforts to cost-effectively identify and address them though the EE/DSM lifecycle.

The payback acceptance function that was applied is presented below in Figure 7-1. This function relates measures' simple payback time, in years, to the likelihood of the measure being adopted by a typical customer. At one year payback 67% of customers are estimated to adopt the measure; 45% would adopt at payback of two years, 30% would adopt at payback of three years, and adoption likelihood drops to 14% or lower after five or more years.

Figure 7-1: Payback Acceptance Curve for Achievable Potential



We used the customer payback acceptance curve to represent the ideal case of well-informed, rational customer decisions with low transaction costs. Owing to these MPS parameters and focus, we describe our estimates as expected EE and DSM potential in a market featuring utility-sponsored programs and incentives. The estimates assume adaptive program management is applied to successfully lower market and non-market barriers to customer adoption over time; the customer payback acceptance approach addresses only the barriers of investment costs and opportunity costs.

7.2. Achievable Market Potential Scenarios

The achievable market potential scenarios reflect customer adoption of measures that are cost-effective for Duke Energy to offer within an existing program. Customer adoption rates are independent of the program design, as previously described, except for reducing customer first costs by the utility incentive amount. The three scenarios developed for this study are as follows:

- **Base** – reflects current Duke Energy programs and program costs, incentive rates, and utility avoided cost benefits generated by the program
- **High Incentive** – doubles current incentive rates with a cap at 100% of the measure incremental cost; applies utility avoided cost benefits from the base scenario
- **High Avoided Costs** – increases utility avoided cost benefits by 50%, uses base scenario incentive rates

7.3. Market Diffusion

Achievable market potential describes a subset of customers expected to take advantage of Duke Energy EE and DSM programs. Data concerning individual customer purchases of EE and DSM equipment are not widely available and may be sparse in their coverage of EE and DSM measure opportunities. EPA's ENERGY STAR program estimates the market penetration of certified products, and EIA's periodic market assessments provide the primary basis for understanding current market penetration of EE technology.

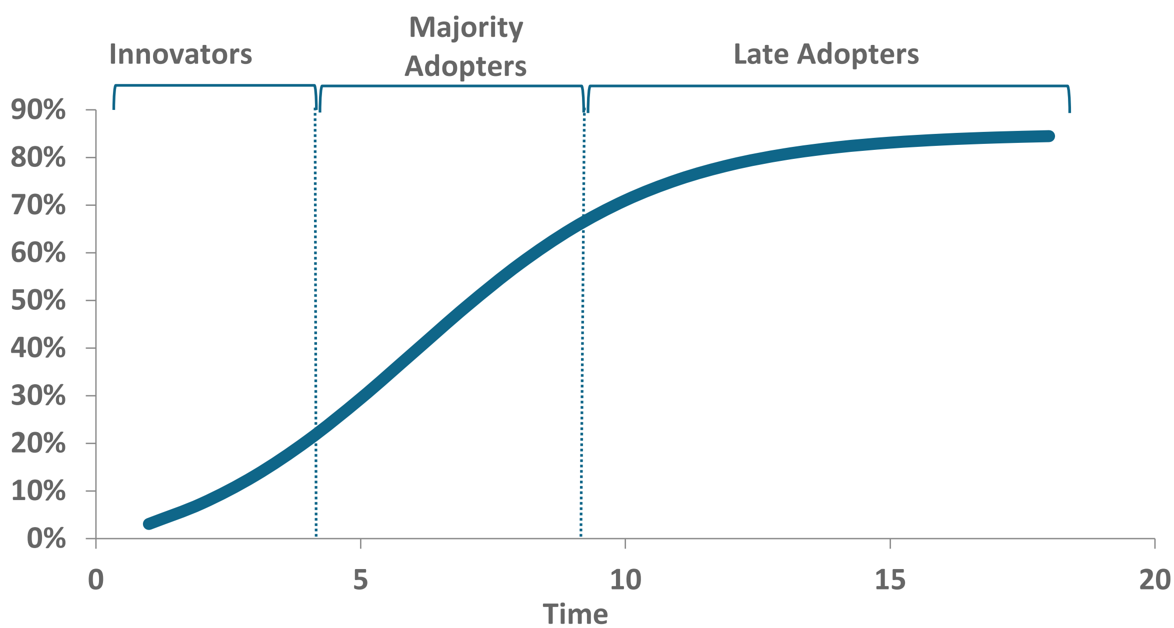
In addition to these sources, Duke Energy conducts residential appliance saturation surveys (RASS) to better understand the energy consumption of residential customers in the Duke Energy service territory. Commercial and industrial building and equipment baselines are limited to the modeling and analysis available from EIA, Duke Energy forecasting, and Duke Energy customer data.

We apply the Bass diffusion model to estimate technology market penetration from customer adoptions over time. The Bass model is a widely accepted description of how new products and innovations spread through an economy over time. It was originally published in 1969, and in 2004 was voted one of the top 10 most influential papers published in the 50-year history of the peerreviewed publication *Management Science*[14]. More recent publications by Lawrence Berkeley National Laboratories have illustrated the application of this model to conservation and demand management (CDM) in the energy industry[15].

RI applied general technology diffusion curves describing expected market familiarity with EE and DSM measures, which will be enhanced by the ongoing efforts of Duke Energy and stakeholders. The curves represent effective program marketing and sophisticated customer recruitment of cost-effective measures that meet customer payback acceptance criteria.

According to product diffusion theory, the rate of market adoption for a product changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of cumulative market saturation is illustrated in Figure 7-2.

Figure 7-2: Bass Model Cumulative Market Penetration



[14] Bass, F. 2004. Comments on "A New Product Growth for Model Consumer Durables the Bass Model" (sic). *Management Science* 50 (12_supplement): 1833-1840. http://pubsonline.informs.org/doi/abs/10.1287/mnsc.1040.0300. Accessed 01/08/2016.
[15] Buskirk, R. 2014. Estimating Energy Efficiency Technology Adoption Curve Elasticity with Respect to Government and Utility Deployment Program Indicators. LBNL Paper 6542E. Sustainable Energy Systems Group, Environmental Energy Technologies Division. Ernest Orlando Lawrence Berkeley National Laboratory. http://escholarship.org/uc/item/2vp2b7cm#page-1. Accessed 01/14/2016.

The Bass Diffusion model is a mathematical description of how the rate of new product diffusion in a market changes over time. Figure 1 depicts the cumulative market adoption with respect to time, $S(t)$. The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters. The following equation describes this relationship:

$$\frac{dS(t)}{dt} = \left(p + \frac{q}{m} * S(t-1)\right) * (m - S(t-1))$$

Where:

$\frac{dS(t)}{dt}$ = the rate of adoption for any discrete time period, t

p = external influences on market adoption

q = internal influences on market adoption

m = the maximum market share for the product

$S(t-1)$ = the cumulative market share of the product, from product introduction to time period *t-1*

Marketing is the quintessential external influence. The internal influences are characteristics of the product and market; for example: the underlying market demand for the product, word of mouth, product features, market structure, and other factors that determine the product's market performance. RI's approach applied literature reviews and analysis of secondary data sources to estimate the Bass model parameters. We then extrapolated the model to future years; the historic participation and predicted future market evolution serve as the program adoption curve applied to each proposed offering.

7.4. DSM Achievable Market Potential

Duke Energy offered DSM programs for over 10 years, covering a variety of approaches for load management such as direct utility control; contractual programs for guaranteed load drop and emergency load management; and load control programs that incentivize economic load response. These offer types are described in Table 7-1.

Table 7-1: DSM Technologies covered by Duke Energy Programs

Type of DSM	Sector	Technology
Utility controlled loads	Residential	▪ Central AC switches ▪ Smart thermostat ▪ Water heater switches ▪ Home gateway (control HVAC, water heater, pool pumps, power strips) ▪ Pool pumps
	Non-Residential	▪ Lighting controls (EMS or lighting ballasts) ▪ HVAC controls (EMS) ▪ Pump loads ▪ Auto DSM for process loads ▪ Battery storage ▪ Backup generation
Contractual	Non-Residential	▪ Interruptible rates – Firm service levels ▪ Guaranteed Load Drop ▪ Emergency Load Response ▪ Economic Load Response

7.4.1. Participation Rates for DSM Programs

While economic potential examines marginal net benefits provided by customers, achievable program potential takes into account the estimated participation rate and how that affects the overall cost-effectiveness of the customer segment. The magnitude of DSM resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), and how programs are marketed. How predisposed are specific customers to participate in DSM? What are details of specific offers and how do they influence enrollment rates? What is the level of marketing intensity and what marketing tactics are employed?

For program-based DSM, participation rates are calculated as a function of the incentives offered to each customer group. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DSM potential from that segment should be included in the achievable program potential. The following subsections describe how marketing/incentive level, participation rates, and technology costs are handled by this study.

7.4.2. Marketing and Incentive Levels for Programs

Several underlying assumptions are used to define three different marketing levels. The number of marketing attempts and the method of outreach are varied by marketing level, as described in Table 7-2. The enhanced case assumes a high marketing level for program-based DSM, while the base case assumes a medium marketing level (the low marketing level was not utilized for this study). Within each marketing level, the participation rate for each customer segment is a function of the incentive level.

The specific tactics included in the low, medium, and high marketing scenarios are not prescriptive but are instead designed to provide concrete details about the assumptions used in the study. There is a wide range of strategies and tactics that can attain the same enrollment levels and the best approach for a jurisdiction is best developed through testing and optimizing the mix of marketing - tactics and incentives.

Table 7-2: Marketing Inputs for Residential Program Enrollment Model

Input	Marketing Level			
	No Marketing	Low	Medium	High
Number of marketing attempts (Direct mail)	0	5	5	8
Outreach mode	No marketing	Direct Mail	DM + Phone	DM + Phone
Installation required (%)	0%	100%	100%	100%
Attrition Rate	7.5%	7.5%	7.5%	7.5%

The incentive level and marketing inputs for each scenario determine the participation rate, assuming that the incentive is uniform across all customer segments within a given customer class.

7.4.3. Participation Models

The participation models for the residential and nonresidential customer segments use a bottom-up approach to estimate participation rates. These estimates have been crosschecked with mature programs in other jurisdictions to ensure that the estimated participation rates are reasonable.

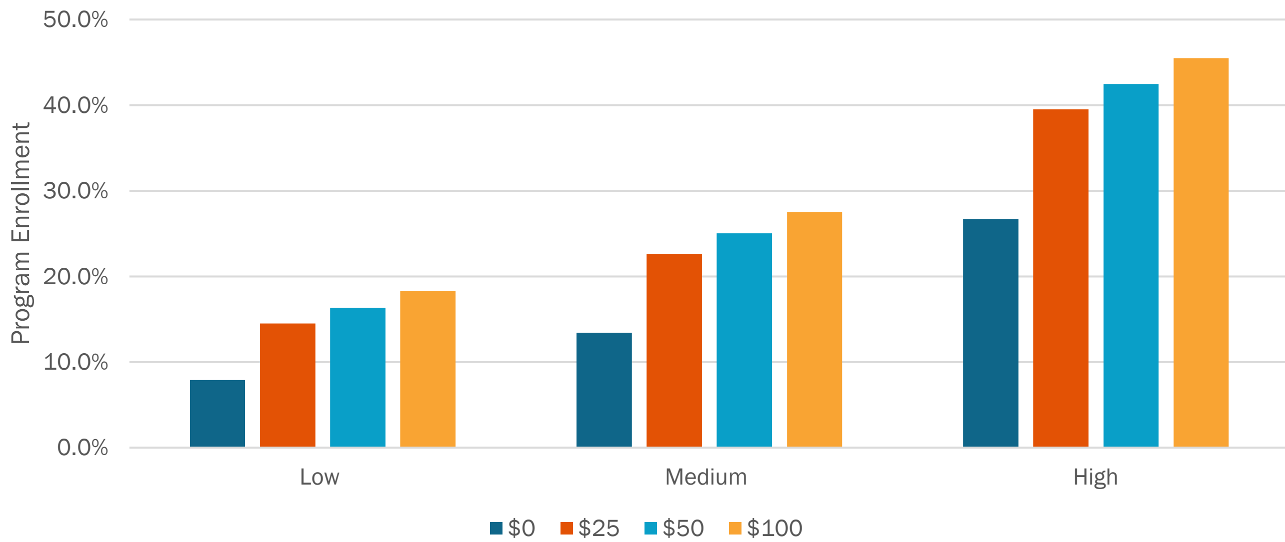
Many DSM potential studies rely on top-down approaches which benchmark programs against enrollment rates that have been attained by mature programs. However, aggregated program results often do not provide enough detail to calibrate achievable program potential. In many cases, programs are not marketed to all customers, either because it is not cost-effective to market to all customers or budgets are capped by regulators. Enrollment rates are a function of specific offers and the extensiveness of marketing over many years. They also vary based on the degree to which DSM resources are utilized and tend to be higher when payments are high but actual events are infrequent, particularly among large C&I customers.

For residential customers, the RI approach to estimate participation rates involves five steps. The initial step required some modification due available data:

- Estimate an econometric choice model based on who has and has not enrolled in DSM programs. The goal is to estimate the pre-disposition or propensity of different customers to participate in DR based on their characteristics. Because micro-level acquisition marketing data were not provided, we relied on differences in participation rates by usage level and electric heating. This information is based on prior micro-level analysis of program participation by RI.
- Incorporate information about how different offer characteristics influence enrollment likelihood. What is the incremental effect of incentives? How do requirements for on-site installation affect enrollment rates? The two questions above have been analyzed using mature market specific data for residential customers. In each case, regression coefficients describe the incremental effect of each of the above factors on participation rates. It is important to note that while this element of the participation model was derived using non-Duke Energy specific data, it is only being used to determine the incremental impact of additional incentives on participation (i.e., how does increasing the sign-up incentive increase participation in DSM programs). The underlying assumption is that customers' response to incremental financial incentives is similar across various geographic regions. Finally, as will be described in subsequent steps, the final participation model is calibrated too, so the baseline level of enrollment reflects the DEC and DEP territories.
- Incorporate information about how marketing tactics and intensity of marketing influence participation rates. What is the effect of incremental acquisition attempts? Is there a bump in enrollment rates when phone and/or door-to-door recruitment is added to direct mail recruitment? This relies on data from side-by-side testing designed to explicitly quantify the effect of marketing tactics on enrollment rates.
- Calibrate the models to reflect actual enrollment rates attained by programs in DEC and DEP territories used for benchmarking.
- Predict participation rates using specific tactics and incentive levels for programs with and without installation requirements. The enrollment estimates were produced for low, medium, and high marketing levels, where specific marketing tactics are specified for each scenario. All estimates reflect enrollment rates for eligible customers.

As a demonstration of how marketing level and incentive affects participation in DSM programs, Figure 7-3 shows an example of how the range of participation rates for each marketing level varies at several different incentive levels.

Figure 7-3: Program Enrollment for Residential Customer Segments Under Different Marketing and Incentive Levels



For SMB customers, a similar approach was used to estimate participation levels. However, these customers tend to have lower enrollments than larger nonresidential customers and were scaled accordingly. SMB customers tend to exhibit roughly 40% of the uptake of residential customers, based on data from other utilities, which have extensively marketed these programs. We noted that current Duke Energy enrollments are somewhat lower than projections based on benefit cost analysis, but we adhered to the approach of focusing on benefit cost analysis and assuming programs lower market barriers over time. A description of this approach is presented in the introduction to Section 7. We also learned from Duke Energy that the SMB program focus will shift to a “bring-your-own-kW’ approach for recruiting participants to provide winter DSM capacity. This change reflects a shift from direct utility load control to more of a price-response program. While this change increases the total available capacity to all coincident winter loads from SMB customers, price-response programs have historically been considered to be roughly half as effective as direct load control programs; we therefore expect enrollment rates to decline while the program contemporaneously expands to recruit load from additional end uses.

For large nonresidential customers, enrollment levels were predicted as a function of load rather than the number of customers, since large customers tend to have relatively high participation rates and commit to relatively large demand reductions on a percentage basis. For these customers, publicly available data on DSM programs offered by other utilities were used to model program participation rates. Participation data were combined with data from the utilities on customer size and industry to generate a breakdown of participation rates, which is summarized in Table 7-3.

Table 7-3: Large Nonresidential Participation Rates by Size and Industry

Industry	Annual Max Demand (Non-coincident)				Total
	100kW-300kW*	300-500kW	500kW-1MW	1MW or more	
Agriculture, Mining & Construction	19.8%	43.2%	57.9%	60.7%	**44.6%**
Manufacturing	24.2%	44.8%	52.3%	74.0%	**64.6%**
Wholesale, Transport & Other Utilities	27.9%	50.1%	55.7%	60.8%	**49.7%**
Retail Stores	28.1%	53.0%	53.8%	48.0%	**42.7%**
Offices, Hotels, Finance, Services	13.0%	26.9%	34.3%	40.2%	**30.0%**
Schools	15.0%	30.5%	40.3%	52.5%	**35.7%**
Institutional/Government	13.7%	34.1%	42.8%	62.3%	**40.4%**
Other or Unknown	9.4%	25.3%	29.6%	29.5%	**18.6%**
Total	**19.7%**	**40.8%**	**45.6%**	**60.8%**	**45.4%**

These programs have been marketed to every large non-residential customer in a mature market, which reflect a saturated market and a good representation of the total potential. For each large non-residential customer segment, participation was estimated as a function of incentive level and number of dispatch hours, based on publicly available information on program capacity, dispatch events, and incentive budgets. Finally, for DEC territory, these models were calibrated to reflect actual enrollment from DEC marketing initiatives for the Power Manager® (residential) and PowerShare® (non-residential) programs. For DEP territory, these models were calibrated to reflect the EnergyWise (residential) and CIG DRA (non-residential) programs.

7.4.4. Scenario Analysis

Base and Enhanced scenarios were constructed for the DSM potential analysis, which align with the assumptions for the EE scenarios (notably, the penetration of smart thermostats and the incremental energy savings associated with behavioral demand response). The Base Scenario assumes a modest increase in DSM scope from current Duke Energy offerings, while the Enhanced Scenario assumes more aggressive expansion. Major assumptions for both scenarios are listed below:

Program Potential - Base

- Assume residential load control will only target AC/heating loads
- Offer incentives for smart thermostats
- Medium marketing level for DR programs
- Target only customer segments who are cost-effective on their own

Program Potential - Enhanced

- 50% higher incentives for residential and nonresidential DR programs compared to current levels
- Target pool pumps and water heating in addition to AC/heating for residential customers
- Aggressively increase program marketing and outreach budgets (high marketing level)
- Target all customer segments that can be included without making the program cost prohibitive (UCT<1.0)

7.5. DEC Energy Efficiency Program Potential

This section provides the results of the DEC EE achievable program potential for each of the three segments.

7.5.1. Summary

Table 7-4 summarizes the short-term (5-year), medium (10-year) and long-term (25-year) DEC portfolio EE program potential for the base, high incentive, and the high avoided cost scenarios. Impacts are presented as both cumulative impacts and annual incremental impacts at each time step. The cumulative impacts view is important when using MPS results for resource planning purposes because it accounts for how the incremental addition of EE savings will impact the overall system load and load impacts likely to occur as measures reach the end of their useful lives. Annual impacts align with how utilities report their EE achievements in annual cost recovery filings.

Table 7-4: DEC EE Program Potential

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (MWh)	579,363	615,519	525,878
High Incentive	Annual Incremental Energy (MWh)	686,428	724,304	586,078
High Avoided Cost	Annual Incremental Energy (MWh)	588,942	624,389	527,666
Base	Annual Incremental Summer Peak Demand (MW)	122	129	111
High Incentive	Annual Incremental Summer Peak Demand (MW)	147	154	125
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	125	132	111
Base	Annual Incremental Winter Peak Demand (MW)	102	109	95
High Incentive	Annual Incremental Winter Peak Demand (MW)	122	129	107
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	103	110	96
Base	Cumulative Energy (MWh)	1,588,163	2,846,544	2,998,660
High Incentive	Cumulative Energy (MWh)	2,057,621	3,833,315	4,205,006
High Avoided Cost	Cumulative Energy (MWh)	1,620,726	2,881,450	3,007,027
Base	Cumulative Summer Peak Demand (MW)	325	574	585
High Incentive	Cumulative Summer Peak Demand (MW)	432	798	860
High Avoided Cost	Cumulative Summer Peak Demand (MW)	334	583	587
Base	Cumulative Winter Peak Demand (MW)	255	460	489
High Incentive	Cumulative Winter Peak Demand (MW)	339	644	729
High Avoided Cost	Cumulative Winter Peak Demand (MW)	257	462	489

We assigned measures to Duke Energy programs for all achievable market potential scenarios; programs apply to either residential or non-residential customers, so we will combine the commercial and industrial economic sectors in subsequent reporting. In the base scenario and the high avoided cost scenarios both see residential potential as 53% of the total and non-residential as 47%. Only in the high incentive case does this ratio change, with the residential share increasing to 58% of the total. Participant and program costs associated with achievable program potential scenarios include the following:

- **Program incentives:** Financial incentives paid by energy-efficiency programs to subsidize purchases of energy-efficiency measures.
- **Program administration costs:** Administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy-efficiency savings.
- **Total program acquisition costs:** Total incentive and non-incentive program costs per sum of annual incremental energy savings achieved.
- **Participant costs:** Incremental costs to purchase, install, and maintain energy-efficiency measures, less utility incentives.

Table 7-5 lists estimated participant and program costs associated with the theoretically achievable scenarios over the first 5 program years.

Table 7-5: DEC Participation and Program Costs by Scenario (cumulative through 2027)

Scenario	Program Sector	Program Incentives ($M)	Program Admin ($M)	Participant Costs ($M)	Levelized Cost ($/kWh)
Base	Residential	$105.32	$139.68	$221.78	$0.08
Base	NonRes	$78.06	$62.71	$164.32	$0.04
Base	Total	$206.78	$239.22	$450.41	$0.07
High Incentive	Residential	$417.29	$283.89	$575.28	$0.18
High Incentive	NonRes	$194.60	$94.74	$259.47	$0.06
High Incentive	Total	$653.81	$390.69	$885.82	$0.12
High Avoided Cost	Residential	$152.91	$220.40	$329.07	$0.13
High Avoided Cost	NonRes	$94.80	$78.62	$197.71	$0.05
High Avoided Cost	Total	$265.08	$279.72	$563.82	$0.08

7.5.2. Residential Program Details

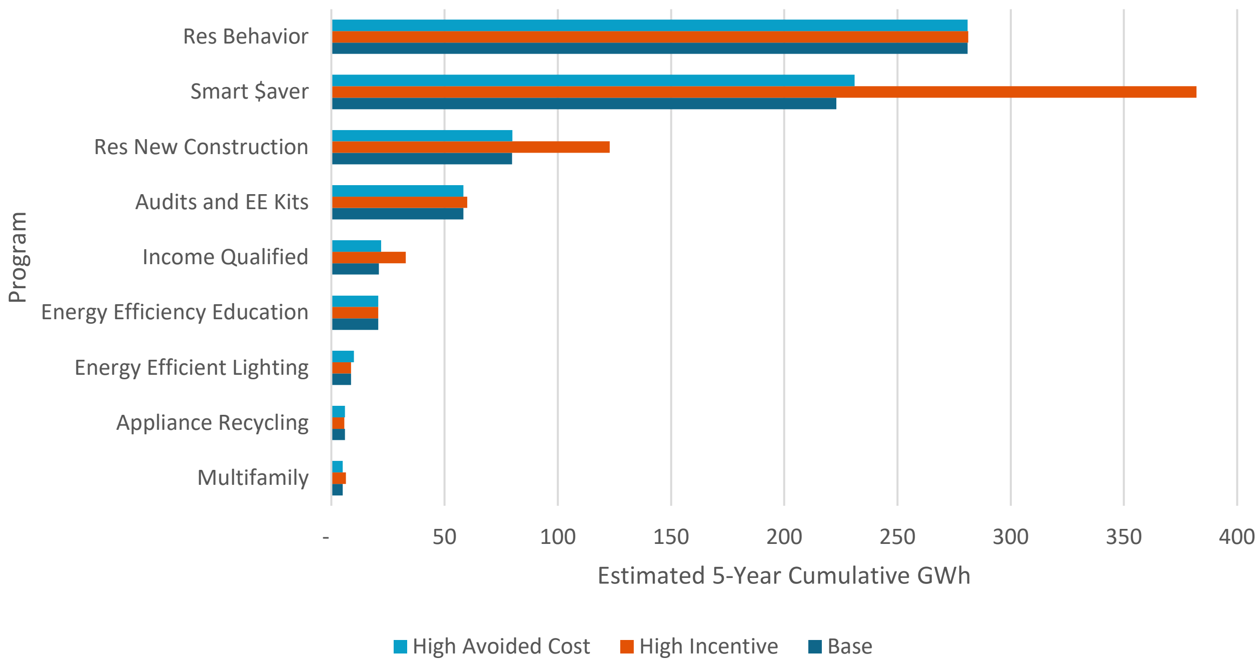
Table 7-6 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base, high incentive, and high avoided cost scenarios. Impacts are presented as both cumulative impacts and annual incremental impacts over the stated time horizon (5 years, 10 years, or 25 years):

Table 7-6: EE Residential Program Potential

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (MWh)	383,101	416,235	406,583
High Incentive	Annual Incremental Energy (MWh)	436,293	472,659	444,857
High Avoided Cost	Annual Incremental Energy (MWh)	386,671	419,611	406,929
Base	Annual Incremental Summer Peak Demand (MW)	86	93	90
High Incentive	Annual Incremental Summer Peak Demand (MW)	99	107	100
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	87	95	91
Base	Annual Incremental Winter Peak Demand (MW)	78	85	81
High Incentive	Annual Incremental Winter Peak Demand (MW)	92	99	90
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	79	85	81
Base	Cumulative Energy (MWh)	703,344	1,213,362	1,418,872
High Incentive	Cumulative Energy (MWh)	920,636	1,713,360	2,182,081
High Avoided Cost	Cumulative Energy (MWh)	713,792	1,225,755	1,420,378
Base	Cumulative Summer Peak Demand (MW)	156	273	313
High Incentive	Cumulative Summer Peak Demand (MW)	210	397	500
High Avoided Cost	Cumulative Summer Peak Demand (MW)	161	278	314
Base	Cumulative Winter Peak Demand (MW)	145	254	290
High Incentive	Cumulative Winter Peak Demand (MW)	200	380	478
High Avoided Cost	Cumulative Winter Peak Demand (MW)	145	255	290

Figure 7-4, illustrates the relative contributions to the overall residential program potential by program for the base and enhanced scenarios.

Figure 7-4: DEC Residential 5-Yr Cumulative Potential by Program



Detailed program results for the short-term residential EE programs are provided in Table 7-7.

Table 7-7: DEC Residential Program Potential (cumulative through 2027)

Program Scenario	Metric	Appliance Recycling	Audits and EE Kits	Energy Efficiency Education	Energy Efficient Lighting	Income Qualified	Multifamily	Res Behaviour	Res New Construction	Smart $aver
Base	Energy (MWh)	5,968	58,263	20,665	8,739	20,960	4,985	280,972	79,764	223,029
High Incentive		5,783	59,987	20,667	8,734	32,848	6,399	281,275	122,893	382,049
High Avoided Cost		5,968	58,263	20,665	9,968	21,994	4,985	280,972	79,889	231,087
Base	Summer kW	1,115	12,008	4,309	741	5,178	1,141	63,332	18,560	49,668
High Incentive		1,021	12,299	4,309	741	8,137	1,586	63,413	29,163	89,065
High Avoided Cost		1,115	12,008	4,309	741	5,637	1,141	63,332	18,560	53,796
Base	Winter kW	565	12,676	5,002	660	4,820	1,153	57,454	17,088	45,773
High Incentive		563	12,923	5,003	660	7,877	1,467	57,533	26,927	86,664
High Avoided Cost		565	12,676	5,002	660	4,847	1,153	57,454	17,088	46,010
Base	Program Cost ($Thousands)	1,343	36,559	3,306	759	20,552	4,639	27,634	64,231	102,620
High Incentive		1,297	37,805	3,307	759	38,395	6,756	27,656	123,243	290,137
High Avoided Cost		1,343	36,559	3,306	968	22,354	4,639	27,634	64,264	108,636
Base	Levelized Cost ($/kWh)	$0.05	$0.15	$0.04	$0.02	$0.24	$0.23	$0.02	$0.19	$0.11
High Incentive		$0.05	$0.15	$0.04	$0.02	$0.28	$0.26	$0.02	$0.24	$0.18
High Avoided Cost		$0.05	$0.15	$0.04	$0.02	$0.25	$0.23	$0.02	$0.19	$0.11

To analyze the costs and benefits of the program potential scenarios, RI used a number of common test perspectives in the MPS, consistent with the California Standard Practice Manual[16]:

- Total resource cost (TRC): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to that measure's incremental cost. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Utility cost test (UCT): Calculated by comparing total avoided electricity production and avoided delivery costs from installing a measure, to the utility's cost of delivering a program containing that measure. Costs include incentive and non-incentive costs.
- Participant cost test (PCT): Calculated by dividing electricity bill savings for each installed measure, by the incremental cost of that measure. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Ratepayer Impact Measure (RIM): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to the utility's revenue impacts from lost sales and program delivery.

RI shows achievable program potential estimates and benefits cost ratios according to current administrative cost data provided to RI by Duke Energy. Detailed program design is not part of this

[16] California Standard Practice Manual: Economic Analysis of Demand-Side Program and Projects. California Public Utilities Commission. San Francisco, CA. October 2001.

scope of work; RI examined the components of the administrative costs provided by Duke Energy and applied them on a dollar-per-kilowatt-hour basis.

Table 7-8 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-8: DEC Cost-Benefit Results – Residential Programs (cumulative through 2027)

Cost-Effectiveness Test	Multifamily	Appliance Recycling	Energy Efficient Lighting	Energy Efficiency Education	Income Qualified	Audits and EE Kits	Res New Construction	Smart $aver	Behavioral
UCT Net Benefits	$2.19	$0.41	$1.48	$6.98	$0.08	$3.82	$51.34	$118.50	$70.96
UCT Ratio	2.29	1.30	3.01	3.11	1.00	1.12	1.88	2.18	3.58
TRC Net Benefits	$1.79	$0.41	$1.42	$6.98	$0.08	$3.82	$21.12	$32.71	$70.96
TRC Ratio	1.86	1.30	2.76	3.11	1.00	1.12	1.24	1.18	3.58
PCT Net Benefits	$3.84	$3.02	$3.48	$12.25	$19.50	$44.50	$76.44	$127.25	$130.29
PCT Ratio	10.76	N/A	54.35	N/A	N/A	N/A	3.53	2.48	N/A
RIM Net Benefits	-$2.05	-$2.61	-$2.06	-$5.28	-$19.43	-$40.67	-$55.32	-$94.54	-$59.3
RIM Ratio	0.65	0.40	0.52	0.66	0.50	0.47	0.66	0.70	0.62

7.5.3. Non-Residential Program Details

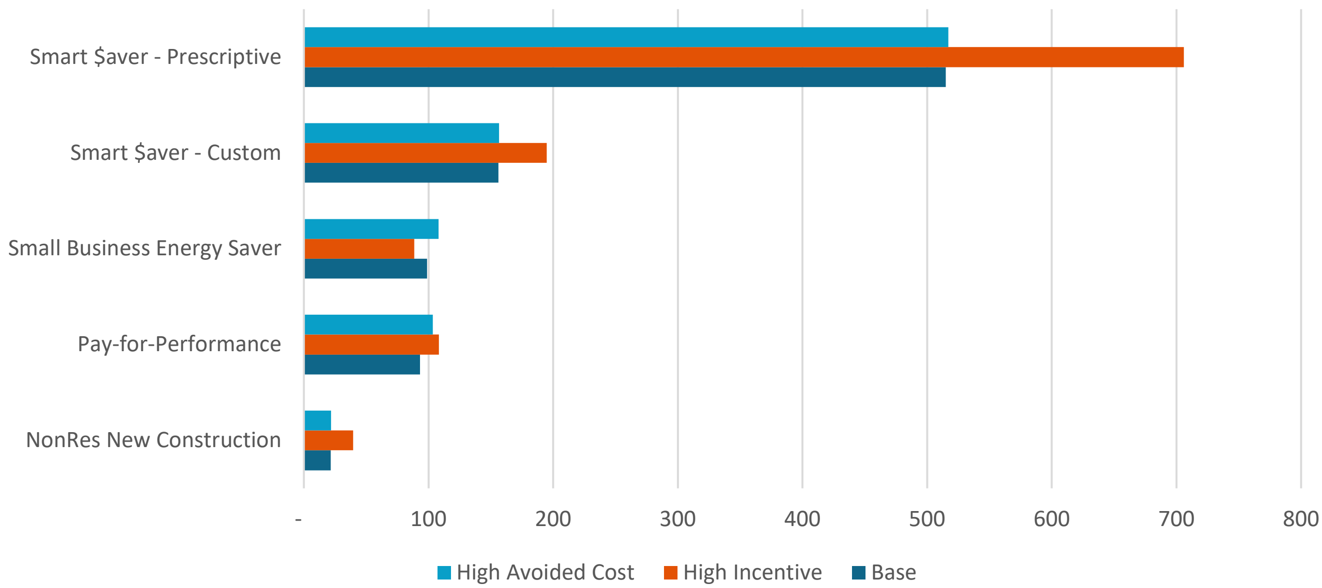
Table 7-9 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base and enhanced scenarios, presented as both cumulative and sum of annual impacts:

Table 7-9: DEC EE Non-Residential Program Potential

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (MWh)	196,262	199,284	119,295
High Incentive	Annual Incremental Energy (MWh)	250,136	251,645	141,221
High Avoided Cost	Annual Incremental Energy (MWh)	202,271	204,778	120,738
Base	Annual Incremental Summer Peak Demand (MW)	37	36	20
High Incentive	Annual Incremental Summer Peak Demand (MW)	48	47	25
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	38	37	21
Base	Annual Incremental Winter Peak Demand (MW)	24	24	15
High Incentive	Annual Incremental Winter Peak Demand (MW)	30	30	17
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	24	25	15
Base	Cumulative Energy (MWh)	884,819	1,633,182	1,579,787
High Incentive	Cumulative Energy (MWh)	1,136,985	2,119,954	2,022,925
High Avoided Cost	Cumulative Energy (MWh)	906,934	1,655,695	1,586,648
Base	Cumulative Summer Peak Demand (MW)	169	301	272
High Incentive	Cumulative Summer Peak Demand (MW)	223	401	359
High Avoided Cost	Cumulative Summer Peak Demand (MW)	174	305	273
Base	Cumulative Winter Peak Demand (MW)	109	206	199
High Incentive	Cumulative Winter Peak Demand (MW)	139	265	251
High Avoided Cost	Cumulative Winter Peak Demand (MW)	111	208	199

Figure 7-5 illustrates the relative contributions to the overall non-residential program potential by program for the base, enhanced, and avoided energy cost sensitivity scenarios.

Figure 7-5: Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario



Detailed program results for the short-term non-residential EE programs are provided in Table 7-10.

Table 7-10: DEC Non-Residential Program Potential (cumulative through 2027)

Program Scenario	Metric	NonRes New Construction	Pay-for-Performance	Small Business Energy Saver	Smart $aver - Custom	Smart $aver - Prescriptive
Base	Energy (MWh)	21,610	93,248	98,727	156,187	515,047
High Incentive		39,422	108,273	88,641	194,800	705,849
High Avoided Cost		21,728	103,482	108,129	156,591	517,004
Base	Summer kW	3,714	23,140	23,195	23,071	96,206
High Incentive		6,675	26,564	20,472	28,923	139,939
High Avoided Cost		3,747	24,338	25,810	23,128	96,500
Base	Winter kW	2,648	6,617	11,036	20,062	69,057
High Incentive		4,710	8,387	10,548	25,052	90,418
High Avoided Cost		2,654	7,792	11,511	20,114	69,323
Base	Program Cost ($Thousands)	5,850	26,309	27,773	34,809	67,439
High Incentive		14,651	42,092	27,172	54,456	173,281
High Avoided Cost		5,944	36,108	30,899	35,028	68,200
Base	Levelized Cost ($/kWh)	$0.07	$0.07	$0.07	$0.05	$0.03
High Incentive		$0.09	$0.09	$0.07	$0.07	$0.06
High Avoided Cost		$0.07	$0.08	$0.07	$0.05	$0.03

Table 7-11 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-11: DEC Cost-Benefit Results – Non-Residential Programs (through 2027)

Cost-Effectiveness Test	NonRes New Construction	Pay-for-Performance	Small Business Energy Saver	Smart $aver - Custom	Smart $aver - Prescriptive
UCT Net Benefits	$15.75	$32.56	$36.71	$80.69	$278.96
UCT Ratio	7.55	2.23	1.75	2.77	4.75
TRC Net Benefits	$14.86	$6.46	$9.04	$42.18	$183.01
TRC Ratio	5.51	1.24	1.32	2.01	2.58
PCT Net Benefits	$20.08	$27.85	$36.18	$93.87	$295.54
PCT Ratio	23.52	3.28	6.14	9.14	6.60
RIM Net Benefits	-$2.82	-$6.16	-$5.77	-$21.40	-$49.68
RIM Ratio	0.87	0.85	0.87	0.80	0.86

7.6. DEP Energy Efficiency Program Potential

This section provides the results of the DEP energy efficiency economic potential for each of the three segments.

7.6.1. Summary

Table 7-12 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) DEP portfolio EE program potential for the base, high incentive, and high avoided cost sensitivity scenarios. Impacts are presented as both cumulative and annual impacts, which represent the total annual incremental savings achieved over the stated time horizon (5 years, 10 years, or 25 years).

Table 7-12: DEP EE Program Potential

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (MWh)	320,986	332,697	303,876
High Incentive	Annual Incremental Energy (MWh)	370,167	381,699	337,883
High Avoided Cost	Annual Incremental Energy (MWh)	330,030	340,909	305,939
Base	Annual Incremental Summer Peak Demand (MW)	66	69	63
High Incentive	Annual Incremental Summer Peak Demand (MW)	77	80	71
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	69	71	64
Base	Annual Incremental Winter Peak Demand (MW)	67	69	64
High Incentive	Annual Incremental Winter Peak Demand (MW)	81	83	73
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	67	70	64
Base	Cumulative Energy (MWh)	911,981	1,665,073	1,891,024
High Incentive	Cumulative Energy (MWh)	1,119,134	2,131,687	2,561,562
High Avoided Cost	Cumulative Energy (MWh)	946,170	1,705,346	1,906,500
Base	Cumulative Summer Peak Demand (MW)	183	335	380
High Incentive	Cumulative Summer Peak Demand (MW)	228	439	532
High Avoided Cost	Cumulative Summer Peak Demand (MW)	192	346	383
Base	Cumulative Winter Peak Demand (MW)	175	326	380
High Incentive	Cumulative Winter Peak Demand (MW)	235	457	565
High Avoided Cost	Cumulative Winter Peak Demand (MW)	178	329	382

We assigned measures to Duke Energy programs for all achievable market potential scenarios; programs apply to either residential or non-residential customers, so we will combine the commercial and industrial economic sectors in subsequent reporting. As with the DEC territory, the residential sector represents the majority of potential. In the base scenario and the high avoided cost scenarios both see residential potential as 57% and 58% of the total in each scenario, while non-residential constitutes 43% and 42%. Only in the high incentive case does this ratio change, with the residential share increasing to 62% of the total.

Participant and program costs associated with achievable program potential scenarios include the following:

- **Program incentives:** Financial incentives paid by energy-efficiency programs to subsidize purchases of energy-efficiency measures.
- **Program administration costs:** Administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy-efficiency savings.
- **Total program acquisition costs:** Total incentive and non-incentive program costs per sum of annual incremental energy savings achieved.
- **Participant costs:** Incremental costs to purchase, install, and maintain energy-efficiency measures.

Table 7-13 lists estimated participant and program costs associated with the theoretically achievable scenarios over the first 5 program years.

Table 7-13: DEP Participant and Program Costs by Scenario (cumulative through 2027)

Scenario	Program Sector	Program Incentives ($M)	Program Admin ($M)	Participant Costs ($M)	Levelized Cost ($/kWh)
Base	Residential	$105.32	$139.68	$221.78	$0.08
Base	NonResidential	$78.06	$62.71	$164.32	$0.04
Base	Total	$206.78	$239.22	$450.41	$0.07
High Incentive	Residential	$417.29	$283.89	$575.28	$0.18
High Incentive	NonResidential	$194.60	$94.74	$259.47	$0.06
High Incentive	Total	$653.81	$390.69	$885.82	$0.12
High Avoided Cost	Residential	$152.91	$220.40	$329.07	$0.13
High Avoided Cost	NonResidential	$94.80	$78.62	$197.71	$0.05
High Avoided Cost	Total	$265.08	$279.72	$563.82	$0.08

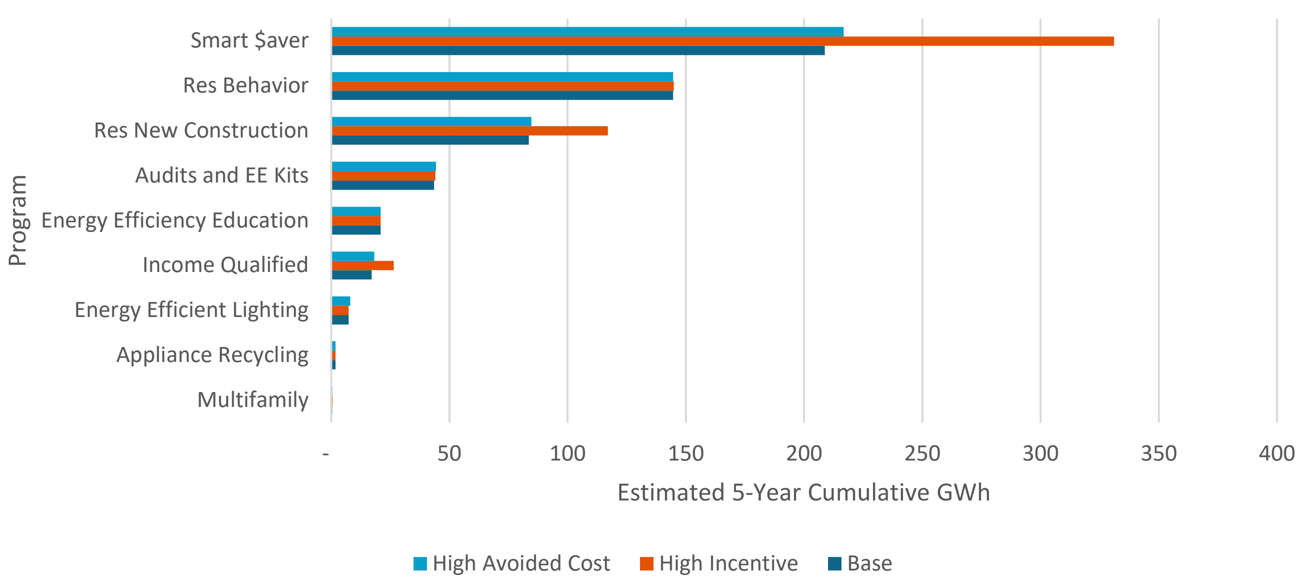
7.6.2. Residential Program Details

Table 7-14 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for base, enhanced, and avoided energy cost sensitivity scenarios.

Table 7-14: DEP EE Residential Program Potential

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (MWh)	236,483	252,328	258,346
High Incentive	Annual Incremental Energy (MWh)	276,559	292,560	287,014
High Avoided Cost	Annual Incremental Energy (MWh)	240,248	255,822	258,982
Base	Annual Incremental Summer Peak Demand (MW)	51	55	56
High Incentive	Annual Incremental Summer Peak Demand (MW)	61	64	63
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	53	56	56
Base	Annual Incremental Winter Peak Demand (MW)	56	60	59
High Incentive	Annual Incremental Winter Peak Demand (MW)	69	72	67
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	57	60	59
Base	Cumulative Energy (MWh)	528,052	969,889	1,273,757
High Incentive	Cumulative Energy (MWh)	694,000	1,335,306	1,825,372
High Avoided Cost	Cumulative Energy (MWh)	539,586	984,495	1,277,642
Base	Cumulative Summer Peak Demand (MW)	114	212	274
High Incentive	Cumulative Summer Peak Demand (MW)	153	298	404
High Avoided Cost	Cumulative Summer Peak Demand (MW)	119	218	275
Base	Cumulative Winter Peak Demand (MW)	128	239	305
High Incentive	Cumulative Winter Peak Demand (MW)	180	354	474
High Avoided Cost	Cumulative Winter Peak Demand (MW)	129	241	306

Figure 7-6: DEP Residential 5-Yr Cumulative Potential by Program – Base Scenario



Detailed program results for the short-term residential energy efficiency programs are provided in Table 7-15.

Table 7-15: DEP Residential Program Potential (cumulative through 2027)

Program Scenario	Metric	Appliance Recycling	Audits and EE Kits	Energy Efficiency Education	Energy Efficient Lighting	Income Qualified	Multifamily	Res Behaviour	Res New Construction	Smart $aver
Base	Energy (MWh)	1,815	43,510	20,846	7,351	17,157	446	144,618	83,594	208,714
High Incentive		1,786	44,034	20,849	7,348	26,432	577	144,855	116,996	331,124
High Avoided Cost		1,815	44,300	20,846	8,007	18,205	446	144,618	84,640	216,709
Base	Summer kW	267	8,681	4,310	530	4,074	101	31,657	18,844	45,430
High Incentive		254	8,750	4,310	530	6,148	141	31,719	26,858	73,869
High Avoided Cost		267	8,853	4,310	613	4,544	101	31,657	19,029	49,410
Base	Winter kW	191	11,024	5,892	472	4,699	121	33,905	20,750	50,880
High Incentive		190	11,090	5,894	472	7,716	155	33,977	29,860	90,540
High Avoided Cost		191	11,247	5,892	547	4,763	121	33,905	20,965	51,157
Base	Program Cost ($T)	402	26,186	3,335	716	18,675	414	14,553	69,057	100,824
High Incentive		395	26,387	3,336	715	34,169	608	14,572	120,654	266,962
High Avoided Cost		402	27,339	3,335	864	20,550	0	14,553	69,627	106,774
Base	Levelized Cost ($/kWh)	$0.05	$0.15	$0.04	$0.02	$0.26	$0.22	$0.02	$0.20	$0.12
High Incentive		$0.05	$0.14	$0.04	$0.02	$0.31	$0.25	$0.02	$0.25	$0.19
High Avoided Cost		$0.05	$0.15	$0.04	$0.03	$0.27	$0.00	$0.02	$0.20	$0.12

Table 7-16 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-16: Cost-Benefit Results – Residential Programs (cumulative through 2024)

Cost-Effectiveness Test	Multifamily	Appliance Recycling	Energy Efficient Lighting	Energy Efficiency Education	Income Qualified	Audits and EE Kits	Res New Construction	Smart $aver	Behavioral
UCT Net Benefits	$0.28	$0.18	$1.09	$8.85	$2.73	$8.55	$75.37	$155.98	$48.02
UCT Ratio	2.65	1.45	2.56	3.65	1.15	1.36	2.20	2.58	4.32
TRC Net Benefits	$0.23	$0.18	$1.01	$8.85	$2.73	$8.55	$42.31	$66.96	$48.02
TRC Ratio	2.12	1.45	2.30	3.65	1.15	1.36	1.44	1.36	4.32
PCT Net Benefits	$0.40	$1.06	$3.13	$13.88	$18.79	$37.16	$93.87	$141.45	$75.84
PCT Ratio	10.32	N/A	40.11	N/A	N/A	N/A	3.84	2.59	N/A
RIM Net Benefits	-$0.16	-$0.88	-$2.12	-$5.03	-$16.05	-$28.61	-$51.56	-$74.50	-$27.8
RIM Ratio	0.73	0.40	0.46	0.71	0.56	0.53	0.73	0.77	0.69

7.6.3. Non-Residential Program Details

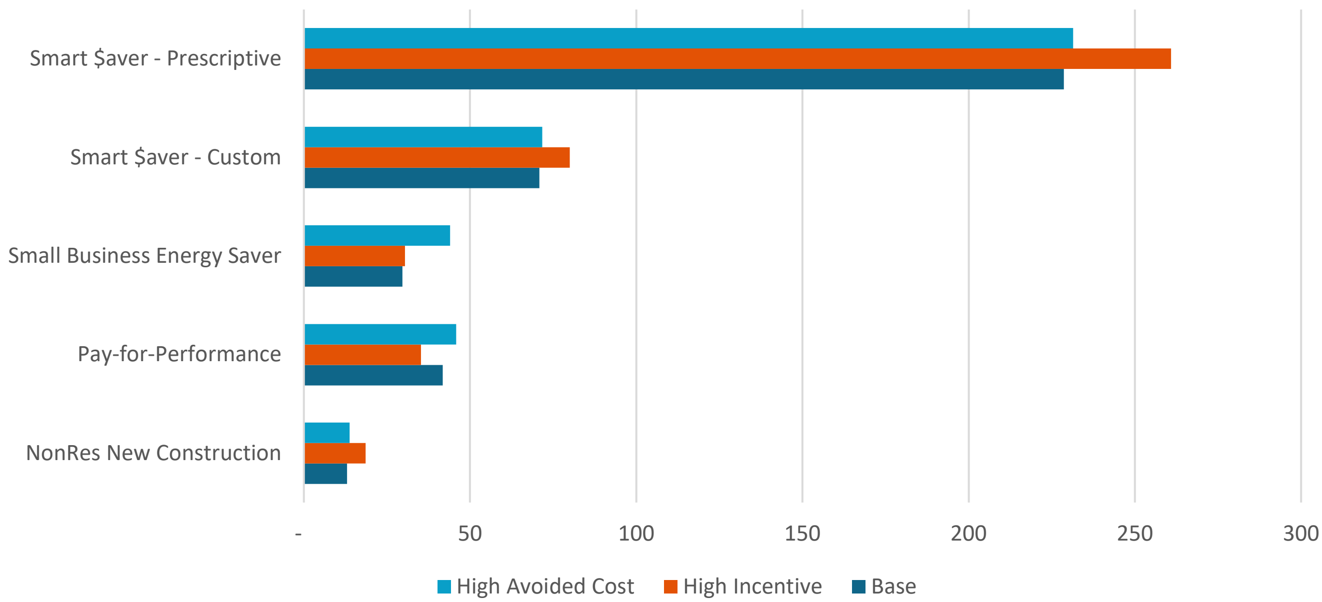
Table 7-17 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base, enhanced, and avoided energy cost sensitivity scenarios:

Table 7-17: DEP EE Non-Residential Program Potential

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (MWh)	84,504	80,368	45,529
High Incentive	Annual Incremental Energy (MWh)	93,608	89,139	50,869
High Avoided Cost	Annual Incremental Energy (MWh)	89,782	85,087	46,957
Base	Annual Incremental Summer Peak Demand (MW)	15	14	8
High Incentive	Annual Incremental Summer Peak Demand (MW)	16	16	9
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	16	15	8
Base	Annual Incremental Winter Peak Demand (MW)	10	10	5
High Incentive	Annual Incremental Winter Peak Demand (MW)	12	11	6
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	11	10	5
Base	Cumulative Energy (MWh)	383,929	695,184	617,268
High Incentive	Cumulative Energy (MWh)	425,133	796,381	736,190
High Avoided Cost	Cumulative Energy (MWh)	406,583	720,851	628,858
Base	Cumulative Summer Peak Demand (MW)	69	123	106
High Incentive	Cumulative Summer Peak Demand (MW)	75	140	128
High Avoided Cost	Cumulative Summer Peak Demand (MW)	74	128	108
Base	Cumulative Winter Peak Demand (MW)	48	87	75
High Incentive	Cumulative Winter Peak Demand (MW)	55	103	91
High Avoided Cost	Cumulative Winter Peak Demand (MW)	49	89	76

Figure 7-7 illustrates the relative contributions to the overall non-residential program potential by program for the base, enhanced, and avoided energy cost sensitivity scenarios.

Figure 7-7: DEP Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario



Detailed program results for the DEP short-term non-residential EE programs are provided in Table 7-18.

Table 7-18: DEP Non-Residential Program Potential (cumulative through 2024)

Program Scenario	Metric	NonRes New Construction	Pay-for-Performance	Small Business Energy Saver	Smart $aver - Custom	Smart $aver - Prescriptive
Base	Energy (MWh)	13,019	41,744	29,662	70,848	228,655
High Incentive		18,601	35,207	30,391	80,013	260,921
High Avoided Cost		13,746	45,789	43,957	71,671	231,420
Base	Summer kW	2,151	9,122	5,928	10,073	41,629
High Incentive		3,049	7,445	6,142	11,301	47,309
High Avoided Cost		2,325	9,605	9,374	10,187	42,048
Base	Winter kW	1,462	2,936	3,967	9,188	30,002
High Incentive		2,052	2,665	4,046	10,347	36,252
High Avoided Cost		1,503	3,394	4,797	9,289	30,300
Base	Program Cost ($T)	3,715	12,676	8,782	16,565	34,138
High Incentive		7,112	15,403	9,516	21,770	63,987
High Avoided Cost		4,297	16,694	13,612	17,245	35,656
Base	Levelized Cost ($/kWh)	$0.07	$0.07	$0.07	$0.06	$0.04
High Incentive		$0.09	$0.11	$0.08	$0.07	$0.06
High Avoided Cost		$0.08	$0.09	$0.07	$0.06	$0.04

Table 7-19 provides the net benefits and benefit-to-cost ratios by sector for each scenario.

Table 7-19: Cost-Benefit Results – Non-Residential Programs (cumulative through 2024)

Cost-Effectiveness Test	NonRes New Construction	Pay-for-Performance	Small Business Energy Saver	Smart $aver - Custom	Smart $aver - Prescriptive
UCT Net Benefits	$9.01	$13.06	$11.18	$27.58	$107.56
UCT Ratio	6.64	1.83	1.66	2.18	3.95
TRC Net Benefits	$8.32	$0.13	$2.31	$11.02	$64.53
TRC Ratio	4.65	1.01	1.24	1.55	2.06
PCT Net Benefits	$11.35	$10.95	$11.25	$32.88	$116.89
PCT Ratio	17.57	2.83	5.64	6.77	5.01
RIM Net Benefits	-$1.43	-$3.49	-$1.79	-$7.66	-$20.64
RIM Ratio	0.88	0.79	0.87	0.80	0.86

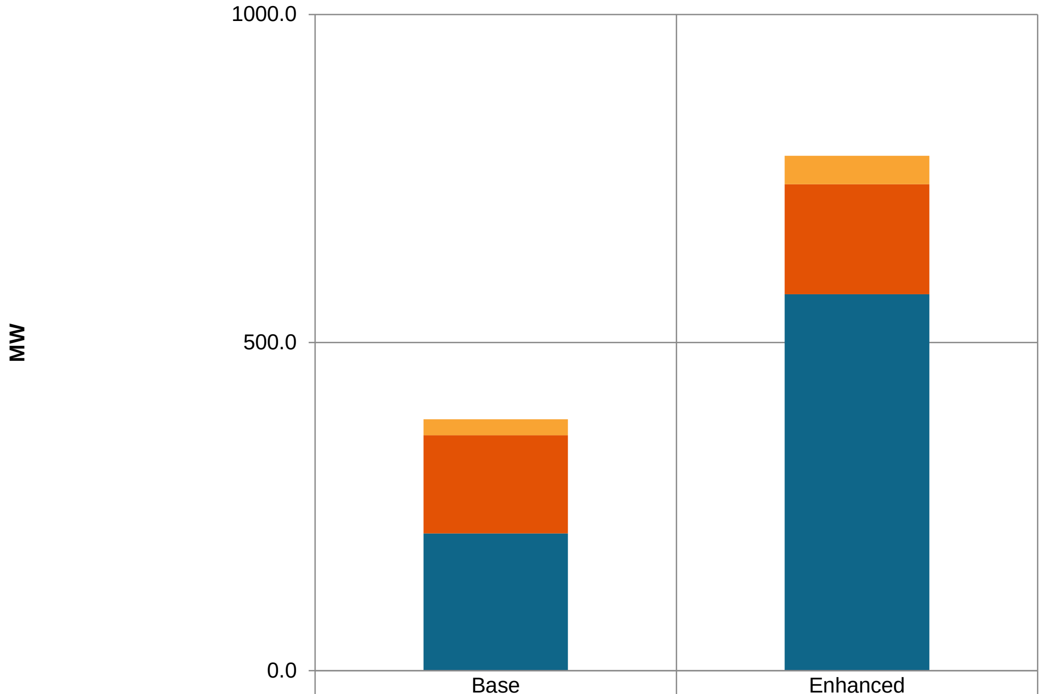
7.7. DEC DSM Achievable Market Potential

This section presents the estimated overall achievable market potential for the base and enhance scenarios. The results are provided separately for summer and winter peaking capacity. The results are further broken down by customer segment and presented in the form of supply curves. All results presented reflect the projected achievable DSM potential by 2047.

7.7.1. DEC Summer Peaking Capacity

Figure 7-8 presents the overall summer peak capacity results for both scenarios, broken down by sector. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity comes out to 383 MW in the base scenario and 785 MW in the Enhanced Scenario. This equates to 2.4% of DEC's peak load in the base scenario and 5.0% in the Enhanced Scenario. Most of the peak capacity potential comes from residential and SMB customers. Variation in the peak capacity between the two scenarios can be attributed to differences in incentive levels, the degree of marketing, and technology cost forecasts. DSM is not affected by the avoided cost sensitivity scenario.

Figure 7-8 DEC DSM Summer Peak Capacity Achievable Potential



	Base	Enhanced
Large C&I	24.1	43.1
Small and Medium Business	149.7	168.0
Residential	209.2	573.6

Because the achievable potential is driven by marketing intensity, incentive levels, and technology costs, it is possible to yield non-linear changes in participation level. This can be seen in the program participation results in Table 7-20. Note that this table shows the overall participation rate for each sector, including existing participation in the Power Manager program.

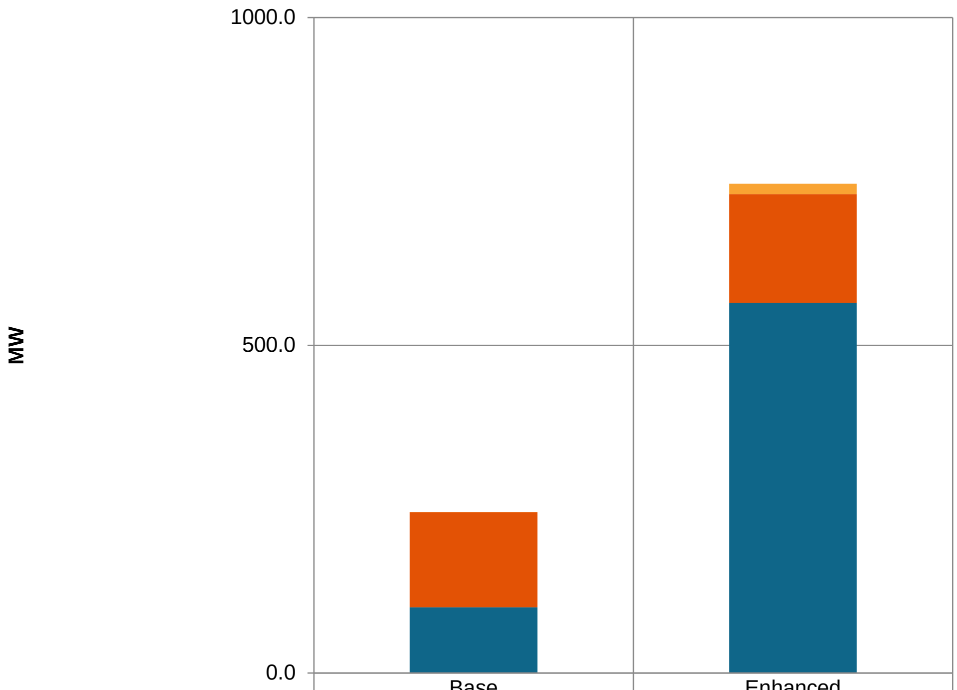
Table 7-20 DEC DSM Program Participation Rates by Scenario and Customer Class

Customer Class	Base	Enhanced	Units
Residential Electric Heating	15%	30%	% of Customers
SMB	27%	29%	% of Customers
Large C&I	63%	71%	% of Load

7.7.2. DEC Winter Peaking Capacity

Figure 7-9 presents the overall winter peak capacity results for both scenarios, broken down by sector. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity is 246 MW in the Base Scenario and 747 MW in the Enhanced Scenario. This equates to 1.6% of DEC's winter peak load in the base scenario and 4.9% of the winter peak in the enhanced scenario.

Figure 7-9 DEC DSM Winter Peak Capacity Achievable Potential



	Base	Enhanced
Large C&I	0.1	16.4
Small and Medium Business	145.1	165.6
Residential	100.5	564.9

7.7.3. Segment specific results

A total of 58 different customer segments were individually analyzed. This includes 3 segments each for gas and electric heated residential customers (6), 26 industry types for SMB customers, and 26 industries for large commercial and industrial customers. This section presents the segment-level results, focusing on the customer segments that are most attractive to pursue, allowing for prioritization and targeted marketing of those customer segments.

These results are fairly similar across the two scenarios that were studied, with the main difference being the magnitude of the overall resources being larger for the enhanced scenario due to higher participation rates across all sectors and the inclusion of additional residential end uses dramatically increasing the residential DSM capacity. For the sake of simplicity, only the results for the base scenario are presented in this section. Table 7-21 shows the cost/benefit details for residential customer segments. Most of the customer segments are cost-effective under the base case assumptions to pursue for DSM enrollment. Residential customers who rank in the top tertile of consumption provide the greatest benefit/cost ratio. This is not surprising since they tend to have the greatest load available for load reduction, making it possible to enroll significant capacity per marginal dollar spent on acquisition marketing, equipment, and installation costs. Also, the Base Scenario does not consider pool pumps, there is not much incremental DSM capacity. Inclusion of pool pumps in the Enhanced Scenario provides 91 MW of summer capacity.

SMB customers do not provide much DSM capacity comparably, due to their being a relatively small portion of the overall system load and having lower participation rates. The retail, assembly and lodging/hospitality customer segments provide the most capacity reduction opportunities.

There is minimal DSM potential from the large C&I sector. These customers tend to already have considerably high participation rates. The participation rate presented here represents the percentage of the overall peak period load from each customer segment that would be available for curtailment if DSM programs are properly incentivized and marketed. They reflect a saturated market (i.e., all customers are properly informed of the program and given the opportunity to enroll).

Table 7-22 and Table 7-23 show the segment specific achievable potential results for each non-residential sector.

Table 7-21: DEC Residential Segment Specific Achievable Potential

Segmentation		Residential			Summer		Winter		Total Aggregate Net Benefit ($M)	Total Net Benefit per Customer ($)
	Usage Bin	**# of Accounts**	**Participation Rate**	**Total Cost ($M)**	**Agg. MW**	**Total Benefit ($M)**	**Agg. MW**	**Total Benefit ($M)**		
Electric Heating	1	398,871	14.21%	$41	63.0	$8	110.8	$95	$87	$1,537
	2	398,871	12.88%	$37	73.0	$9	115.0	$102	$97	$1,883
	3	398,871	16.05%	$46	111.1	$13	166.5	$153	$148	$2,313
Gas Heating	1	224,365	18.48%	$18	46.1	$6	-	$0	($24)	($582)
	2	224,365	13.92%	$14	44.4	$5	-	$0	($17)	($544)
	3	224,365	20.43%	$20	79.5	$10	-	$0	($23)	($507)
Total AC/Heating Achievable Potential					247.2		392.3			
Additional Potential from WH and PP					-		50.2			
Total Program Potential (Unadjusted)					247.2		442.5			
Total Potential (Adjusted for existing DSM)					209.2		100.5			

Table 7-22: DEC SMB Segment Specific Achievable Potential

SMB		Summer				Winter			
Segment	Participation %	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)
Assembly	18.52%	21.3	$2.97	$24.6	$4,351	11.8	$2.2	$13.6	$4,053
College and University	18.52%	1.2	$0.12	$1.4	$6,151	0.8	$0.2	$0.9	$7,604
Data Center	30.61%	3.5	$0.10	$4.0	$23,205	4.6	$0.9	$5.4	$47,209
Grocery	34.88%	4.5	$0.52	$5.2	$5,325	2.1	$0.4	$2.5	$4,115
Healthcare	19.29%	7.4	$0.80	$8.6	$5,778	9.4	$1.8	$10.9	$12,033
Hospitals	18.52%	0.6	$0.06	$0.7	$5,936	6.3	$1.2	$7.2	$102,501
Institutional	18.52%	6.5	$1.22	$7.5	$3,103	4.9	$0.9	$5.7	$3,000
Lodging/Hospitality	19.29%	16.7	$0.40	$19.3	$28,171	13.8	$2.6	$15.9	$36,366
Miscellaneous	19.04%	1.2	$0.50	$1.4	$1,055	0.9	$0.2	$1.1	$1,212
Office	19.29%	17.9	$5.90	$20.7	$1,502	18.7	$3.5	$21.6	$2,692
Restaurants	19.29%	6.7	$1.07	$7.8	$3,753	3.0	$0.6	$3.5	$3,028
Retail	34.88%	29.0	$9.61	$33.5	$1,490	25.5	$4.7	$29.4	$2,453
Schools K-12	16.33%	5.7	$0.45	$6.6	$8,125	6.9	$1.3	$8.0	$17,287
Warehouse	30.61%	6.5	$0.27	$7.5	$15,768	4.3	$0.8	$4.9	$4,428
Agriculture and Assembly	31.01%	3.5	$0.90	$4.1	$2,109	4.9	$0.9	$5.6	$6,227
Chemicals and Plastics	26.71%	1.3	$0.12	$1.5	$6,888	1.0	$0.2	$1.1	$9,153
Construction	31.01%	6.4	$2.00	$7.4	$1,624	5.3	$1.0	$6.1	$3,068
Electrical and Electronic Equip.	26.71%	0.1	$0.28	$0.2	($225)	1.0	$0.2	$1.2	$4,320
Lumber/Furniture/Pulp/Paper	26.71%	0.7	$0.33	$0.8	$815	2.1	$0.4	$2.5	$7,496
Metal Products and Machinery	26.71%	2.0	$0.36	$2.3	$3,302	4.7	$0.9	$5.4	$14,981
Miscellaneous Manufacturing	26.71%	2.3	$0.50	$2.7	$2,613	2.0	$0.4	$2.3	$4,702
Primary Resources Industries	31.01%	NA	NA	$0.1	NA	0.1	$0.0	$0.1	$256
Stone/Clay/Glass/Concrete	26.71%	0.5	$0.06	$0.6	$4,748	3.3	$0.6	$3.8	$60,272
Textiles and Leather	26.71%	2.0	$0.13	$2.4	$10,554	5.0	$0.9	$5.8	$45,564
Transportation Equipment	30.61%	0.8	$0.93	$1.0	$25	1.2	$0.2	$1.4	$1,503
Water and Wastewater	30.61%	1.0	$1.29	$1.1	($72)	1.5	$0.3	$1.7	$1,315
Total Potential (Adjusted)		148.5				145.1			

Table 7-23: DEC Large C&I Segment Specific Achievable Potential

Large C&I			Total Benefits				Annual Achievable Potential	
Segment	Participation Rate	# of Participating Accounts	Total Cost ($M)	Total Benefits ($M)	Total Net Benefit per Customer ($)	Summer Agg MW	Winter Agg MW
Assembly	52.34%	1	$0.2	$1.0	$1,390,065	0.8	0.9
College and University	52.34%	0	$0.0	$0.0	NA	-	-
Data Center	55.15%	2	$8.8	$35.7	$12,209,092	29.7	19.0
Grocery	81.47%	0	$0.0	$0.0	NA	-	-
Healthcare	55.15%	0	$0.0	$0.0	NA	-	-
Hospitals	52.34%	0	$0.0	$0.0	NA	-	-
Institutional	52.34%	0	$0.0	$0.0	NA	-	-
Lodging/Hospitality	55.15%	0	$0.0	$0.0	NA	-	-
Miscellaneous	32.99%	1	$1.3	$5.1	$2,934,460	4.3	7.2
Office	55.15%	3	$3.9	$15.7	$4,295,583	13.0	10.6
Restaurants	81.47%	0	$0.0	$0.0	NA	-	-
Retail	81.47%	1	$0.0	$0.1	$119,470	0.1	0.5
Schools K-12	43.14%	0	$0.2	$0.6	$1,114,448	0.5	0.4
Warehouse	71.38%	0	$0.0	$0.0	NA	-	-
Agriculture and Assembly	76.22%	0	$0.0	$0.0	NA	-	-
Chemicals and Plastics	71.01%	5	$8.6	$35.0	$5,312,538	29.1	22.5
Construction	71.38%	0	$0.0	$0.0	NA	-	-
Electrical and Electronic Equip.	71.01%	1	$0.3	$1.0	$1,080,677	0.8	1.0
Lumber/Furniture/Pulp/Paper	71.01%	4	$1.6	$6.5	$1,373,361	5.4	9.4
Metal Products and Machinery	71.01%	1	$1.2	$5.1	$2,682,765	4.2	4.3
Miscellaneous Manufacturing	71.01%	3	$2.2	$9.0	$2,377,308	7.4	5.0
Primary Resources Industries	76.22%	0	$0.0	$0.0	NA	-	-
Stone/Clay/Glass/Concrete	71.01%	1	$1.2	$4.7	$5,005,758	3.9	3.6
Textiles and Leather	71.01%	4	$16.5	$66.9	$11,837,573	55.6	47.3
Transportation Equipment	71.38%	1	$0.6	$2.6	$2,756,562	2.2	1.4
Water and Wastewater	71.38%	1	$0.4	$1.8	$934,699	1.5	1.3
Total Potential (Unadjusted)						158.5	134.5
Total Potential (Adjusted)						24.1	0.1

7.7.4. Key Findings

The overall DSM potential is estimated to be 383 MW of peak summer capacity in the base scenario and 785 MW under the assumption of aggressive marketing. The overall DSM potential for the peak winter capacity is estimated to be 246 MW in the base scenario and 747 MW in the enhanced scenario. These estimates are based on an in-depth, bottom-up assessment of load reduction potential of all customer segments and includes an analysis of pricing and program-based DSM.

The extent to whether these potential figures can be attained in a cost-effective manner by 2047 depends on the ability to implement programs that target all possible end-uses and cost-effective customer segments. These estimates rely upon assumptions around the future value of capacity.

The customer segment-level analysis of the program- and pricing-based DSM potential sheds light on which customer segments can provide the greatest magnitude of capacity, as well as which customer segments are most cost-effective to pursue. Unsurprisingly, the most attractive customer segments from a benefit/cost perspective are customers who have more load available for reduction during peak hours: residential customers, retail, assembly, and lodging/hospitality customers. In general, these customers are more capable of shifting load with little inconvenience/cost, and therefore tend to have higher participation levels in DSM programs as well as greater willingness to shed a higher percentage of their load.

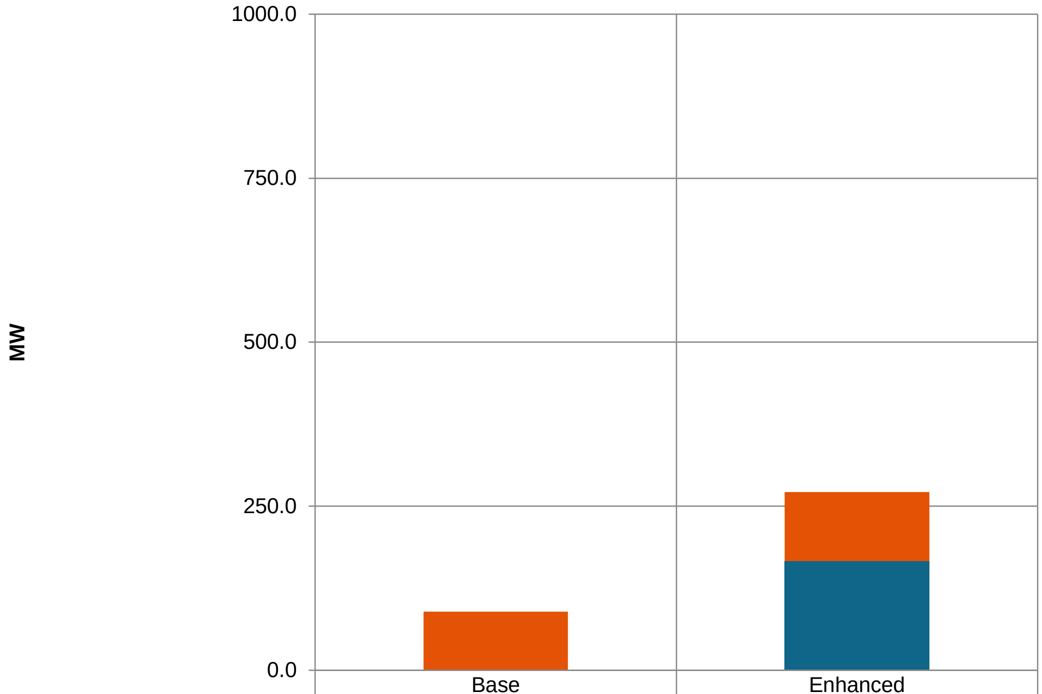
7.8. DEP DSM Achievable Market Potential

This section presents the estimated overall achievable market potential for the base and enhance scenarios. The results are provided separately for summer and winter peaking capacity. The results are further broken down by customer segment and presented in the form of supply curves. All results presented reflect the projected achievable DSM potential by 2047.

7.8.1. DEP Summer Peaking Capacity

Figure 7-10 presents the overall summer peak capacity results for both scenarios, broken down by sector. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity comes out to 84 MW in the Base Scenario and 272 MW in the enhanced scenario. This equates to 1.0% of DEP's peak load in the base scenario and 3.0% in the enhanced scenario. Most of the peak capacity potential comes from SMB customers, as Duke Energy avoided costs currently place no weight on summer capacity values. While winter-enrolled DSM customer do provide some summer capacity, Duke Energy's currently enrolled capacity exceeds our potential estimates for summer DSM from these customers (this is due to removing existing summer DR customers, which were presumable recruited when Duke Energy was a winter-peaking system). Variation in the peak capacity between the two scenarios can be attributed to differences in incentive levels, the degree of marketing, and technology cost forecasts. DSM is not affected by the avoided cost sensitivity scenario.

Figure 7-10 DEP DSM Summer Peak Capacity Achievable Potential



	Base	Enhanced
Large C&I	0.0	0.0
Small and Medium Business	89.3	105.5
Residential	0.0	166.3

Because the achievable potential is driven by marketing intensity, incentive levels, and technology costs, it is possible to yield non-linear changes in participation level. This can be seen in the program participation results in Table 7-24. Note that this table shows the overall participation rate for each sector, including existing participation in the Energy Wise program.

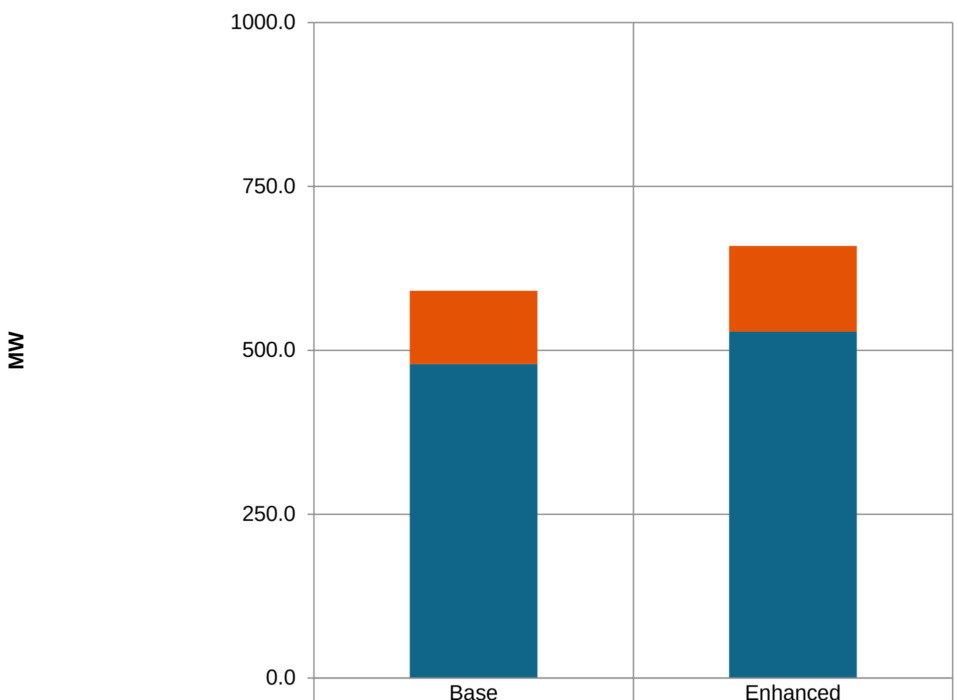
Table 7-24 DEP DSM Program Participation Rates by Scenario and Customer Class

Customer Class	Base	Enhanced	Units
Residential Electric Heating	22.7%	37.1%	% of Customers
SMB	22.7%	25.7%	% of Customers
Large C&I	66.9%	65.0%	% of Load

7.8.2. DEP Winter Peaking Capacity

Figure 7-11 presents the overall winter peak capacity results for both scenarios, broken down by sector. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity is 591 MW in the base scenario and 659 MW in the Enhanced Scenario. This equates to 5.8% of DEP's winter peak load in the base scenario and 6.4% of the winter peak in the enhanced scenario.

Figure 7-11 DEP DSM Winter Peak Capacity Achievable Potential



	Base	Enhanced
Large C&I	0.0	0.0
Small and Medium Business	111.5	131.2
Residential	479.1	528.1

7.8.3. Segment specific results

A total of 58 different customer segments were individually analyzed. This includes 3 segments each for gas and electric heated residential customers (6), 26 industry types for SMB customers, and 26 industries for large commercial and industrial customers. This section presents the segment-level results, focusing on the customer segments that are most attractive to pursue, allowing for prioritization and targeted marketing of those customer segments.

These results are fairly similar across the two scenarios that were studied, with the main difference being the magnitude of the overall resources being larger for the enhanced scenario due to higher participation rates across all sectors and the inclusion of additional residential end uses dramatically increasing the residential DSM capacity. For the sake of simplicity, only the results for the Base Scenario are presented in this section.

Table 7-25 shows the cost/benefit details for residential customer segments. Only electric heating customers are cost-effective under the base case assumptions to pursue for DSM enrollment. Residential customers who rank in the top tertile of consumption provide the greatest benefit/cost ratio. This is not surprising since they tend to have the greatest load available for load reduction, making it possible to enroll significant capacity per marginal dollar spent on acquisition marketing, equipment, and installation costs. Also, the base scenario does not consider pool pumps, there is not much incremental DSM capacity. Inclusion of pool pumps in the Enhanced Scenario provides approximately 4 MW of summer capacity.

SMB customers provide the bulk of cost-effective summer DSM capacity, due to their being a relatively cost-effective segment, despite lower participation rates. The electrical and electronic equipment, office and retail customer segments provide the most capacity reduction opportunities.

There is minimal DSM potential from the large C&I sector. These customers tend to already have considerably high participation rates. The participation rate presented here represents the percentage of the overall peak period load from each customer segment that would be available for curtailment if DSM programs are properly incentivized and marketed. They reflect a saturated market (i.e., all customers are properly informed of the program and given the opportunity to enroll).

Table 7-26 and Table 7-27 show the segment specific achievable potential results for each non-residential sector.

Table 7-25: DEP Residential Segment Specific Achievable Potential

Segmentation	Residential				Summer		Winter		Total Aggregate Net Benefit ($M)	Total Net Benefit per Customer ($)
	Usage Bin	**# of Accounts**	**Participation Rate**	**Total Cost ($M)**	**Agg. MW**	**Total Benefit ($M)**	**Agg. MW**	**Total Benefit ($M)**		
Electric Heating	1	292,218	20.1%	$68	64.7	$0	124.5	$78	$74	$1,249
	2	292,218	18.5%	$63	82.0	$0	126.1	$79	$81	$1,503
	3	292,218	22.4%	$76	119.3	$0	190.1	$118	$141	$2,145
Gas Heating	1	131,287	20.1%	$31	29.0	$0	-	-	($31)	($1,160)
	2	131,287	18.5%	$28	36.8	$0	-	-	($28)	($1,160)
	3	131,287	22.4%	$34	53.6	$0	-	-	($34)	($1,160)
Dual Season HVAC DR Capacity					266.00		440.65			
Additional Seasonal Potential from WH and PP					49.53		46.62			
Total Seasonal Potential (Unadjusted)					315.53		487.28			
Total Seasonal Potential (Adjusted for Existing DR)					-		479.1			

Table 7-26: DEP SMB Segment Specific Achievable Potential

SMB		Summer				Winter			
Segment	Participation %	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)	Agg. MW	Total Cost ($M)	Total Benefit ($M)	Total Net Benefit per Customer ($)
Assembly	14.63%	3.8	$2.7	$4.2	$1,191	4.5	$3.7	$5.1	$2,143
College and University	14.63%	0.5	$0.1	$0.6	$8,320	1.0	$0.9	$1.1	$6,804
Data Center	27.28%	0.8	$0.1	$1.0	$18,552	1.3	$1.1	$1.4	$16,396
Grocery	32.49%	2.3	$0.8	$2.6	$4,391	1.8	$1.5	$2.0	$2,845
Healthcare	15.36%	2.0	$1.0	$2.2	$2,378	2.5	$2.1	$2.8	$3,010
Hospitals	14.63%	0.7	$0.1	$0.8	$15,003	0.8	$0.6	$0.9	$8,965
Institutional	14.63%	1.0	$1.6	$1.2	($548)	4.0	$2.4	$4.5	$5,464
Lodging/Hospitality	15.36%	4.2	$1.5	$4.8	$4,363	3.6	$3.1	$4.1	$2,682
Miscellaneous	15.12%	0.5	$0.2	$0.5	$4,087	1.0	$0.5	$1.1	$14,804
Office	15.36%	17.8	$18.3	$20.2	$208	17.6	$12.1	$19.9	$1,755
Restaurants	15.36%	4.8	$1.7	$5.4	$4,691	2.5	$2.2	$2.9	$1,740
Retail	32.49%	17.8	$15.4	$20.1	$643	23.4	$17.4	$26.4	$2,432
Schools K-12	12.59%	3.4	$0.5	$3.9	$15,409	3.8	$3.4	$4.3	$7,681
Warehouse	27.28%	2.0	$0.8	$2.2	$3,522	2.0	$0.5	$2.2	$8,792
Agriculture and Assembly	27.74%	2.1	$1.9	$2.4	$461	1.5	$1.4	$1.7	$629
Chemicals and Plastics	22.91%	0.1	$0.1	$0.1	$394	0.3	$0.3	$0.3	$3,693
Construction	27.74%	NA	NA	NA	NA	1.2	$1.1	$1.3	$537
Electrical and Electronic Equip.	22.91%	23.0	$11.9	$26.0	$2,453	26.2	$24.4	$29.6	$1,817
Lumber/Furniture/Pulp/Paper	22.91%	0.9	$0.2	$1.0	$6,954	8.0	$7.5	$9.1	$29,274
Metal Products and Machinery	22.91%	0.9	$0.1	$1.0	$12,691	0.9	$0.9	$1.0	$5,419
Miscellaneous Manufacturing	22.91%	NA	NA	NA	NA	1.0	$0.9	$1.1	$3,284
Primary Resources Industries	27.74%	1.8	$0.9	$2.0	$2,542	0.5	$0.4	$0.5	$426
Stone/Clay/Glass/Concrete	22.91%	NA	NA	NA	NA	0.2	$0.2	$0.2	$2,295
Textiles and Leather	22.91%	NA	NA	NA	NA	0.1	$0.0	$0.1	$496
Transportation Equipment	27.28%	0.6	$1.1	$0.7	($775)	0.4	$0.3	$0.4	$286
Water and Wastewater	27.28%	NA	NA	NA	NA	1.9	$1.8	$2.1	$555
Total Potential (Adjusted)		89.3				111.5			

Table 7-27: DEP Large C&I Segment Specific Achievable Potential

Large C&I				Total Benefits		Annual Achievable Potential	
Segment	Participation Rate	# of Participating Accounts	Total Cost ($M)	Total Benefits ($M)	Total Net Benefit per Customer ($)	Summer Agg MW	Winter Agg MW
Assembly	54.05%	1	$1.40	$0.80	($1,115,836)	0.6	0.7
College and University	54.05%	0	$0.00	$0.00	NA	-	-
Data Center	56.85%	1	$0.37	$0.21	($278,812)	0.2	0.2
Grocery	82.60%	0	$0.00	$0.00	NA	-	-
Healthcare	56.85%	0	$0.00	$0.00	NA	-	-
Hospitals	54.05%	0	$0.00	$0.00	NA	-	-
Institutional	54.05%	3	$9.42	$5.37	($1,497,061)	4.5	3.1
Lodging/Hospitality	56.85%	0	$0.00	$0.00	NA	-	-
Miscellaneous	34.56%	0	$0.00	$0.00	NA	-	-
Office	56.85%	3	$6.63	$3.78	($1,001,358)	3.2	3.0
Restaurants	82.60%	0	$0.00	$0.00	NA	-	-
Retail	82.60%	2	$3.86	$2.20	($1,003,545)	1.9	0.6
Schools K-12	44.83%	0	$0.00	$0.00	NA	-	-
Warehouse	72.82%	1	$1.91	$1.09	($1,129,246)	0.9	0.2
Agriculture and Assembly	77.53%	0	$0.00	$0.00	NA	-	-
Chemicals and Plastics	72.47%	1	$1.91	$1.09	($1,131,955)	0.9	0.7
Construction	72.82%	0	$0.00	$0.00	NA	-	-
Electrical and Electronic Equip.	72.47%	1	$3.40	$1.94	($1,006,267)	1.6	0.4
Lumber/Furniture/Pulp/Paper	72.47%	0	$0.00	$0.00	NA	-	-
Metal Products and Machinery	72.47%	2	$5.52	$3.15	($1,090,261)	2.2	2.7
Miscellaneous Manufacturing	72.47%	2	$5.22	$2.98	($1,031,277)	2.5	2.3
Primary Resources Industries	77.53%	0	$0.00	$0.00	NA	-	-
Stone/Clay/Glass/Concrete	72.47%	0	$0.00	$0.00	NA	-	-
Textiles and Leather	72.47%	0	$0.00	$0.00	NA	-	-
Transportation Equipment	72.82%	0	$0.00	$0.00	NA	-	-
Water and Wastewater	72.82%	0	$0.00	$0.00	NA	-	-
Total Potential (Unadjusted)						18.8	14.0
Total Potential (Adjusted)						0.2	7.6

7.8.4. Key Findings

The overall DSM potential is estimated to be 89.3 MW of peak summer capacity in the base scenario and 271.8 MW under the assumption of aggressive marketing. The overall DSM potential for the peak winter capacity is estimated to be 590.6 MW in the base Scenario and 659.4 MW in the enhanced scenario. These estimates are based on an in-depth, bottom-up assessment of load reduction potential of all customer segments and includes an analysis of pricing and program-based DSM.

The extent to whether these potential figures can be attained in a cost-effective manner by 2047 depends on the ability to implement programs that target all possible end-uses and cost-effective customer segments. These estimates rely upon assumptions around the future value of capacity.

The customer segment-level analysis of the program- and pricing-based DSM potential sheds light on which customer segments can provide the greatest magnitude of capacity, as well as which customer segments are most cost-effective to pursue. Unsurprisingly, the most attractive customer segments from a benefit/cost perspective are customers who have more load available for reduction during peak hours: residential customers, electrical and electronic equipment, office and retail customer segments. In general, these customers are more capable of shifting load with little inconvenience/cost, and therefore tend to have higher participation levels in DSM programs as well as greater willingness to shed a higher percentage of their load.

Appendix A Enclosures

List of Enclosures for this report:

- Enclosure 1: Duke Carolinas MPS Draft Work Plan
- Enclosure 2: Draft Measure List 2021 Carolinas MPS Update
- Enclosure 3: Measure Research Process Memorandum
- Enclosure 4: RI Draft Algorithm and Parameter for Carolinas MPS 2022
- Enclosure 5: RI Draft EE Measure Impacts for Carolinas MPS 2022
- Enclosure 6: RI Response to Collaborative MPS Measure Comments and Questions
- Enclosure 7: Program Workshop Composite

Appendix B All Customers APS

Duke Energy's energy efficiency programs in North Carolina include an "opt-out" provision approved by the North Carolina Utilities Commission. This provision allows non-residential customers receiving electric service at a single site demanding more than 1 megawatt of electric capacity to opt out, along with all accounts in contiguous property. This opt-out provision exempts the customer from the cost recovery mechanism but also eliminates that customer's eligibility for participation in the program.

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke Energy provided RI with current opt-out information for North Carolina, which showed an opt-out rate of approximately 48% of commercial sales and 77% of industrial sales in the DECNC service territory. We incorporated this opt-out rate into the MPS by excluding sales to non-residential that opted out, and we applied the applicable energy efficiency technologies and market adoption rates to the remaining customer base; the results of this analysis are reported in Section 7.

Resource Innovations also estimated achievable potential with the full customer base as a sensitivity. Table presents the results of achievable market potential when all Duke Energy customers are included in the analysis.

Table 7-28: DECNC Energy Efficiency Achievable Potential with All Customers

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (MWh)	882,052	1,047,398	1,071,596
Base	Annual Incremental Summer Peak Demand (MW)	176	207	213
Base	Annual Incremental Winter Peak Demand (MW)	138	161	162
Base	Cumulative Energy (MWh)	2,905,780	5,886,684	8,338,815
Base	Cumulative Summer Peak Demand (MW)	565	1,122	1,537
Base	Cumulative Winter Peak Demand (MW)	410	820	1,147

Duke Energy provided RI with current opt-out information for DEPNC, which showed an opt-out rate of approximately 44% of commercial sales and 74% of industrial sales. We incorporated this opt-out rate into the model by reducing the non-residential sales estimates by the appropriate percentage and applying the applicable energy efficiency technologies and market adoption rates to the remaining sales forecast. Table 7-29 presents the achievable market potential estimates for all DEPNC customers, regardless of opt-out status.

Table 7-29: DEPNC Energy Efficiency Achievable Potential with All Customers

Scenario	Metric	2027	2032	2047
Base	Annual Incremental Energy (kWh)	420,349	468,937	511,998
Base	Annual Incremental Summer Peak Demand (kW)	82	92	102
Base	Annual Incremental Winter Peak Demand (kW)	79	87	94
Base	Cumulative Energy (kWh)	1,352,850	2,646,623	3,738,054

Scenario	Metric	2027	2032	2047
Base	Cumulative Summer Peak Demand (kW)	256	499	707
Base	Cumulative Winter Peak Demand (kW)	230	449	641

Appendix C Inflation Reduction Act

The 2022 Inflation Reduction Act recently made available approximately $360 billion for investments to reduce greenhouse gas emissions and combat climate change. Major federal program included in the IRA are as follows:

- Home energy performance-based whole-house (HOMES) rebates through the Department of Energy (DOE)
- 179D Energy efficient commercial building deduction
- High-efficiency electric home rebate program (DOE)
- 25c Energy Efficient Home Improvement Credit

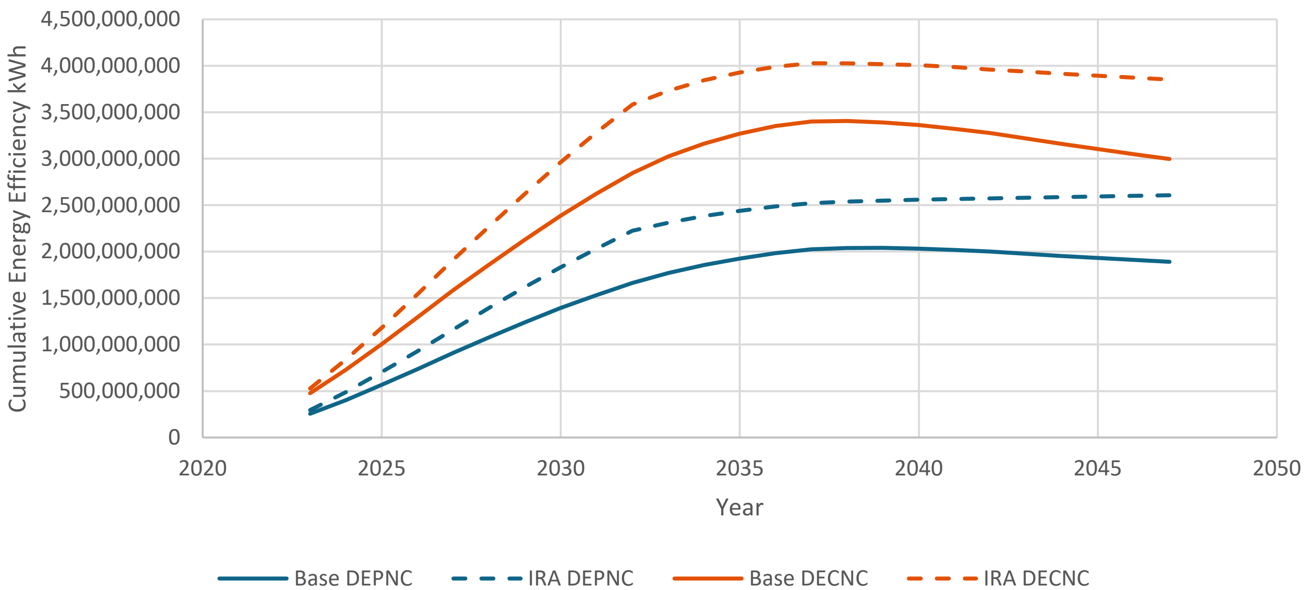
Resource Innovations developed an EE MPS modeling scenario around this legislation in an attempt to address the potential magnitude of expected impacts the program could have on achievable market potential. Significant uncertainty remains concerning how the program will be implemented, but RI's analysis included the following procedures and assumptions, describe below.

- Develop additional, "IRA measures" to supplement the original measure list developed for the MPS
- HOMES includes a whole home retrofit measure that RI developed from the existing "residential new construction 20% improvement" measure
- Measure saves 20% for existing construction, incremental cost is assumed to be 50% higher than the new construction measure
- Measure applies to population in a manner consistent with income distribution; three versions were applied: HOMES for customer base with <80% area median income (AMI), HOMES for customer base with 80%-150% AMI income; and a version of HOMES for non-low-income customers (>150% AMI) was developed and included as a measure in the Duke Energy Residential Smart $aver program
- Measure incremental costs were reduced by the estimated rebate amounts available as a function of income bracket: 80%, 50%, and 0% for <80% AMI, 80%-150% AMI, and >150% AMI.
- Duke Energy incentive rates were also applied to the remaining incremental cost of these measures, commensurate with the Duke Energy income-qualified programs and Residential Smart $aver program
- Administrative costs from relevant Duke Energy programs, on a per-kWh basis, were used to account for the potential of increased program participation volume that may result from the IRA
- High-efficiency Electric Homes Rebates apply to individual measures listed in available materials and research on the potential effects of the IRA; these primarily include shell and envelop retrofit measures. Rebates for equipment were limited to those available for central air conditioning and heat pump clothes dryers, as the program appears to be intended as a stimulus for customer fuel-switching or end-use electrification.
- 25c Tax Energy Efficient Home Improvement Credits apply to all shell and envelope measures, as well as many HVAC and water heating equipment measures (incl. air-source heat pumps, heat pump water heaters, among others), available to all customers.

After developing these measures and cost-estimates, Resource Innovations applied the measures within our model to estimate the potential impacts.

Our results indicate the IRA is likely to increase to the total magnitude of available energy efficiency potential and accelerate the market diffusion of related EE technologies, leading to more rapid adoption and market maturation for these technologies. Given that there is some potential overlap between existing Duke Energy Programs and the IRA measures, we believe the potential IRA impacts are best understood at this time by comparing to results of the base scenario and a model scenario with all base case assumption, plus those described above for IRA measures. While implementation of the IRA may differ substantially from the assumptions made for this analysis, we are providing these estimates in response to MPS client and stakeholder requests.

Figure 7-12: Comparison of Duke Energy Base Case Achievable Potential and Estimated IRA Effects



These estimates, derived from the assumptions described above, indicate the IRA will increase cumulative achievable market potential by 28% in 2027, 34% by 2032, and 38% by 2047. These estimates also assume the IRA rebates will sunset after 10 years and are no longer available by 2033. In terms of measure diffusion and technology adoption, the IRA accelerates market diffusion over this 10-year period. After this 10-year period, IRA incentives are removed, and customer adoption rates are calculated for the remaining period on the basis of Duke Energy program incentives.

Appendix D Combined Heat and Power

The CHP analysis created a series of unique distributed generation potential models for each primary market sector (commercial and industrial). Only non-residential customer segments whose electric and thermal load profiles allow for the application of CHP were considered. The technical potential analysis followed a three-step process to make this determination. Minimum facility electricity consumption thresholds were determined for each non-residential customer segment by applying power-to-heat ratios to customer billing data. The facilities that were of sufficient size were matched with the appropriately sized CHP technology.

To determine the minimum threshold for CHP suitability, a thermal factor was applied to potential candidate customer loads to reflect thermal load considerations in CHP sizing. CHP size is usually dictated by the thermal load in order to achieve improved efficiencies. The study collected electric and thermal intensity data from other recent CHP studies and market analysis. Commercial customers, the thermal load is commonly made up of water heating, space heating, and space cooling (in the case of an absorption chiller). Table 7-3, on the following page, present the values for thermal factors used to estimate technical potential.

Table 7-30: CHP Thermal Factors by Segment and Prime Mover

	Microturbines	Fuel Cells	Reciprocating IC Engines	Reciprocating IC Engines	Gas Turbines	Gas Turbines
Application	250-500 kW	250-500 kW	0.5 - 1 MW	1 - 5 MW	5 - 20 MW	>= 20 MW
Assembly	0.83	0.86	0.92	1.05	1.05	1.28
College and University	0.52	0.54	0.57	0.66	0.66	0.80
Data Center	0.55	0.57	0.61	0.69	0.69	0.85
Grocery	0.12	0.13	0.14	0.15	0.15	0.19
Healthcare	0.38	0.39	0.42	0.48	0.48	0.59
Hospitals	0.70	0.72	0.76	0.87	0.87	1.07
Institutional	0.51	0.53	0.56	0.64	0.64	0.79
Lodging/Hospitality	0.35	0.36	0.39	0.44	0.44	0.54
Miscellaneous	0.33	0.34	0.36	0.42	0.42	0.51
Office	0.37	0.38	0.41	0.46	0.46	0.57
Restaurants	0.33	0.34	0.37	0.42	0.42	0.51
Retail	0.40	0.41	0.43	0.50	0.50	0.61
Schools K-12	0.57	0.58	0.62	0.71	0.71	0.87
Warehouse	0.33	0.33	0.36	0.41	0.41	0.50
Agriculture and Assembly	1.20	1.24	1.32	1.51	1.51	1.85
Chemicals and Plastics	0.74	0.76	0.81	0.93	0.93	1.14
Construction	1.48	1.52	1.63	1.85	1.85	2.27
Electrical and Electronic Equip.	0.29	0.29	0.31	0.36	0.36	0.44
Lumber/Furniture/Pulp/Paper	1.09	1.12	1.19	1.36	1.36	1.67
Metal Products and Machinery	0.29	0.29	0.31	0.36	0.36	0.44
Miscellaneous Manufacturing	1.48	1.52	1.63	1.85	1.85	2.27
Primary Resources Industries	0.38	0.39	0.42	0.48	0.48	0.59
Stone/Clay/Glass/Concrete	2.45	2.52	2.69	3.07	3.07	3.76
Textiles and Leather	0.85	0.87	0.93	1.06	1.06	1.30
Transportation Equipment	0.48	0.49	0.53	0.60	0.60	0.74
Water and Wastewater	0.33	0.34	0.36	0.42	0.42	0.51
Other	0.67	0.69	0.73	0.84	0.84	1.02

RI used the utility-provided customer data to categorize all non-residential customers by segment and size. Customers with annual loads below the consumption thresholds indicated by power-to-heat ratios are not expected to have the consistent thermal loads necessary to support CHP.

In general, internal combustion engines are the prime mover for systems under 500kW with gas turbines becoming progressively more popular as system size increases above that. Based on the available load by customer, adjusted by the estimated thermal factor for each segment, CHP technologies were assigned to utility customers in a top-down fashion (*i.e.,* starting with the largest CHP generators).

Interaction of Technical Potential Impacts

As described above, the technical potential was estimated using separate models for EE, DSM, and CHP systems. However, there is interaction between these technologies; for example, a more efficient HVAC system would result in a reduced peak demand available for DSM curtailment. Therefore, after development of the independent models, the interaction between EE, DSM, and CHP was incorporated as follows:

- The EE technical potential was assumed to be implemented first.
- For CHP systems, the EE technical potential was incorporated in a similar fashion, adjusting the baseline load used to estimate DSRE potential.

For CHP systems, the reduced baseline load from EE resulted in a reduction in the number of facilities that met the annual energy threshold needed for CHP installations. Installed DSM capacity was assumed to not impact CHP potential as the CHP system feasibility was determined based on energy and thermal consumption at the facility. It should be noted that CHP systems not connected to the grid could impact the amount of load available for curtailment with utility-sponsored DSM. Therefore, CHP technical potential should not be combined with DSM potential but used as independent estimates. Table 7-31 presents technical potential for CHP in the DEC jurisdiction.

Table 7-31: DEC Technical Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	2	1	3,089
Commercial	College and University	5	10	35,782
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	6	2	13,365
Commercial	Hospitals	12	6	39,691
Commercial	Institutional	10	3	6,621
Commercial	Lodging/Hospitality	2	1	5,648
Commercial	Miscellaneous	5	6	13,956
Commercial	Office	113	70	171,839
Commercial	Restaurants	0	0	0
Commercial	Retail	50	25	65,097
Commercial	Schools K-12	58	23	60,110
Commercial	Warehouse	10	7	17,824
Industrial	Agriculture and Assembly	2	1	2,787
Industrial	Chemicals and Plastics	5	22	135,177
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	0	0	0
Industrial	Lumber/Furniture/Pulp/Paper	4	12	69,336
Industrial	Metal Products and Machinery	2	3	16,576
Industrial	Miscellaneous Manufacturing	64	49	283,978
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**350**	**239**	**940,875**

The CHP technical potential for DEPNC is presented below in Table 7-32.

Table 7-32: DEP Technical Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	3	1	3,481
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	1	1	7,693
Commercial	Hospitals	7	4	29,156
Commercial	Institutional	4	2	3,594
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	0	0	0
Commercial	Office	64	26	62,400
Commercial	Restaurants	1	0	1,056
Commercial	Retail	30	14	34,998
Commercial	Schools K-12	15	7	18,280
Commercial	Warehouse	6	3	7,638
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	3	6	40,459
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	1	0	1,777
Industrial	Lumber/Furniture/Pulp/Paper	0	0	0
Industrial	Metal Products and Machinery	0	0	0
Industrial	Miscellaneous Manufacturing	22	20	130,067
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**157**	**85**	**340,599**

CHP Economic Potential

RI conducted cost research for CHP prime movers and used research on the technology type to identify the appropriate technologies for each segment. Utility costs for existing CHP incentives, and utility avoided energy costs, were used to estimate UCT ratios for CHP technologies of a given size at each eligible Duke Energy account. Importantly, the assumption the energy efficiency is applied first leads CHP economic potential estimates that are higher than technical potential estimates. This is because the EE reduction from baseline due to economic potential is less than the same adjustment for technical potential. That is to say, the baseline energy consumption for CHPS economic potential is higher than the baseline for technical potential because applying the EE adjustment leads to a higher reduction to baseline in the case of EE technical potential. These estimates are based on 2021 billing data provided by Duke Energy to RI. Economic Potential for DEC is presented below in Table 8-6.

Table 7-33: DEC Economic Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	2	1	3,221
Commercial	College and University	5	10	36,149
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	6	2	14,090
Commercial	Hospitals	12	6	41,147
Commercial	Institutional	10	0	0
Commercial	Lodging/Hospitality	2	1	5,865
Commercial	Miscellaneous	5	0	0
Commercial	Office	113	14	36,659
Commercial	Restaurants	0	0	0
Commercial	Retail	50	0	0
Commercial	Schools K-12	58	5	13,114
Commercial	Warehouse	10	3	7,342
Industrial	Agriculture and Assembly	2	1	2,891
Industrial	Chemicals and Plastics	5	22	138,358
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	0	0	0
Industrial	Lumber/Furniture/Pulp/Paper	4	12	71,190
Industrial	Metal Products and Machinery	2	3	17,150
Industrial	Miscellaneous Manufacturing	64	49	307,155
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**350**	**126**	**694,332**

Economic potential for CHP in the DEP service territory is presented below in Table 7-34.

Table 7-34: DEP Economic Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	3	1	2,646
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	1	1	8,159
Commercial	Hospitals	7	4	30,849
Commercial	Institutional	4	0	0
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	0	0	0
Commercial	Office	64	0	0
Commercial	Restaurants	1	0	0
Commercial	Retail	30	0	0
Commercial	Schools K-12	15	6	18,307
Commercial	Warehouse	6	0	0
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	3	6	41,368
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	1	0	1,854
Industrial	Lumber/Furniture/Pulp/Paper	0	0	0
Industrial	Metal Products and Machinery	0	0	0
Industrial	Miscellaneous Manufacturing	22	20	138,545
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**157**	**39**	**241,727**

CHP Achievable Potential

This analysis describes the physical and economic factors that may contribute to facilities' energy savings through the installation of CHP technologies. The data available for characterizing CHP opportunities are limited to representative values for each commercial and industrial segment.

These values represent general segment characteristics and describe the order of magnitude for likely drivers of CHP potential in each segment.

The question of which specific facilities are more or less likely to adopt CHP potential bears further research. CHP installations are large projects that are inherently site-specific. Assuming CHP is technical feasible and economic at a given location, there are other important considerations for whether CHP should actually go forward. Resource Innovations' understanding is that Duke Energy is currently working through a variety of channels to gauge customer interest in CHP technology. Without further research on the topic, we identified project payback period as a potential criterion for screening eligible. Based on our estimates of cost for CHP prime movers and technical feasibility, we find that payback periods for cost-effective CHP program offers made by Duke Energy should be expected to range from 5.9 to 13.1 years among Duke Energy customers.

As in the energy efficiency potential analysis, we apply a payback acceptance curve to these values to generate an estimate of customer adoption. Customer adoption rates range from a low of 4% to a high of 17% for some segments. The results of this analysis are presented below for DEC:

Table 7-35: DEC Achievable Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	2	0	181
Commercial	College and University	5	0	933
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	6	0	207
Commercial	Hospitals	12	0	1,822
Commercial	Institutional	10	0	0
Commercial	Lodging/Hospitality	2	0	74
Commercial	Miscellaneous	5	0	0
Commercial	Office	113	0	78
Commercial	Restaurants	0	0	0
Commercial	Retail	50	0	0
Commercial	Schools K-12	58	0	52
Commercial	Warehouse	10	0	10
Industrial	Agriculture and Assembly	2	0	142
Industrial	Chemicals and Plastics	5	3	17,511
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	0	0	0
Industrial	Lumber/Furniture/Pulp/Paper	4	2	11,829
Industrial	Metal Products and Machinery	2	0	334
Industrial	Miscellaneous Manufacturing	64	3	21,415
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**350**	**9**	**54,587**

Estimates for achievable potential in the DEP service territory are presented in the following table:

Table 7-36: DEP Achievable Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	3	0	2
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	1	0	323
Commercial	Hospitals	7	0	1,793
Commercial	Institutional	4	0	0
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	0	0	0
Commercial	Office	64	0	0
Commercial	Restaurants	1	0	0
Commercial	Retail	30	0	0
Commercial	Schools K-12	15	0	5
Commercial	Warehouse	6	0	0
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	3	1	3,884
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	1	0	22
Industrial	Lumber/Furniture/Pulp/Paper	0	0	0
Industrial	Metal Products and Machinery	0	0	0
Industrial	Miscellaneous Manufacturing	22	1	7,382
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**157**	**2**	**13,410**

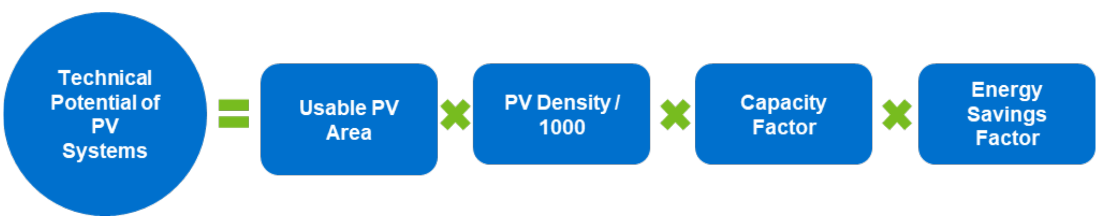
Appendix E Solar PV Potential

To determine technical potential for PV systems, Nexant estimated the percentage of rooftop square footage in North Carolina that is suitable for hosting PV technology. Our estimate of technical potential for PV systems in this report is based in part on the available roof area and consisted of the following steps:

- Step 1: Outcomes from the forecast disaggregation analysis were used to characterize the existing and new residential, commercial and industrial building stocks. Relevant parameters included number of facilities, average number of floors, and average premises square footage.
- Step 2: The total available roof area feasible for installing PV systems was calculated. Relevant parameters included share of pitched and flat roofs and unusable area due to other rooftop equipment.
- Step 3: Estimated the expected power density (kW per square foot of roof area).
- Step 4: Using PVWatts, secondary research, and M&V evaluations of PV systems, Nexant used its technical potential PV calculator to calculate energy generation/savings using researched system capacity factors.

The methodology presented in this report uses the following formula to estimate overall technical potential of PVs:

Equation 5-1: Core Equation for Solar Technical Potential



Where:

Usable PV Area for Residential: (Total Floor Area[17] / Average No. of Stories[18]) x ((% of Sloped Roofs x Usable Area of Sloped Roofs) + (% of Flat Roofs x Usable Area of Flat Roofs))

Usable PV Area for Commercial: Total Floor Area[19] x ((% of Sloped Roofs x Usable Area of Sloped Roofs) + (% of Flat Roofs x Usable Area of Flat Roofs))

[17] Utility-provided data and US Census, South Region
[18] Single Family = RECS, South Atlantic Region; Multi-Family = US Census, South Region https://www.census.gov/construction/chars/mfu.html
[19] Floor space = based on utility data. Average floors by building type = CBECS, South Atlantic Region

PV Density (Watts/Square foot): Maximum power generated in Watts per square foot of solar panel.

Capacity Factor: Annual Energy Generation Factor for PV

Energy Savings Factor: AC Energy Conversion factor for each kW of the system, obtained from PV Watts. Energy Savings Factor = Alternating Current System Output (kWh)/ Direct Current System Size (kW)

The following table describes the analysis results for DEC, with savings potential shown as a share of all 2023 retail sales forecast for all customers, regardless of opt-out eligibility.

Table 7-37: Solar PV Technical Potential for DEC

Potential Breakdown by Year	2023
Residential	
Nameplate Technical Potential (MW)	6,279
Summer Peak Capacity (MW)	1,782
Winter Peak Capacity (MW)	0
Energy Technical Potential (GWh)	1,414
Technical Potential as a % of Residential Sales	12%
Commercial	
Nameplate Technical Potential (MW)	14,179
Summer Peak Capacity (MW)	4,024
Winter Peak Capacity (MW)	0
Energy Technical Potential (GWh)	3,194
Technical Potential as a % of Commercial Sales	24.1%
Total	
Total Energy Potential (GWh)	4,609
Technical Potential as a % of Res+Com Sales	18.1%

Results for DEP are shown below, in the following table.

Table 7-38: Solar PV Technical Potential for DEP

Potential Breakdown by Year	2023
Residential	
Nameplate Technical Potential (MW)	3,961
Summer Peak Capacity (MW)	959
Winter Peak Capacity (MW)	26
Energy Technical Potential (GWh)	852
Technical Potential as a % of Residential Sales	9.4%
Commercial	
Nameplate Technical Potential (MW)	7,556
Summer Peak Capacity (MW)	1,830
Winter Peak Capacity (MW)	50.29
Energy Technical Potential (GWh)	1,625
Technical Potential as a % of Commercial Sales	23.0%
Total	
Total Energy Potential (GWh)	2,477
Technical Potential as a % of Res+Com Sales	15.4%

RI estimated economic and achievable potential by assuming estimated PV costs could be reduced by a 30% Duke Energy incentive and a 30% energy efficiency tax credit. Applying these reductions brings the utility cost to $635 per kW of installed residential PV nameplate capacity, whereas customers still pay the larger share of the cost at approximately $847 per installed kW of residential PV nameplate capacity. Commercial incentives are $312 per installed kW and customer costs are $594 per kW for installed nameplate capacity, respectively. After screening with utility avoided costs and lost revenues, residential solar appears to be a cost-effective to offer for the utility, but commercial PV offers are not. The customer payback time for residential solar is estimated to be 12 years, resulting in an anticipated adoption rate of 3% and a yield of 44 GWh and 3 GWh in DEC and DEP, respectively. The results of the analysis are shown below.

Table 7-39: Residential Estimates of Economic Costs and Benefits of Utility PV Offers

Utility Benefit-Cost Analysis	DEC (NC)	DEP (NC)
Average kWh per customer	749	664
Lifetime kWh per customer	18,723	16,596
Utility Cost ($M)	$639	$394
PV Utility Benefit ($M)	$1,965	$1,184
UCT	3.07	3.00
Customer Cost ($M)	$852	$525
Customer Benefit ($M)	$1,084	$689
PCT	1.27	1.31

The following table describes the benefit-cost analysis results for commercial PV offers sponsored by Duke Energy. For the DEC territory, average lost revenues are higher than in other jurisdictions, resulting in a cost-effective commercial solar PV program opportunity and positive customer benefits. Customer payback period in DEC is estimated to be 5 years, for a 20% adoption rate and APS total of 646 GWh.

Table 7-40: Commercial Estimates of Economic Costs and Benefits of Utility PV Offers

Utility Benefit-Cost Analysis	DEC (NC)	DEP (NC)
Average kWh per customer	623	522
Lifetime kWh per customer	15,587	13,041
Utility Cost ($M)	$4,422	$2,356
PV Utility Benefit ($M)	$6,085	$780
UCT	1.4	0.3
Customer Cost ($M)	$1,897	$965
Customer Benefit ($M)	$4,482	$588
PCT	2.36	0.61