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January 19, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

**RE: Tierra and Dunsky Winter Peak Studies
Docket No. E-100, Sub 165**

Dear Ms. Dunston:

Pursuant to the Commission's August 19, 2021 *Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning*, I enclose the three Winter Peak Studies prepared by Tierra Resource Consultants and Dunsky Engineering Consulting in December 2020:

- Duke Energy Winter Peak Targeted DSM Plan
- Duke Winter Peak Analysis & Solution Set
- Duke Winter Peak Demand Reduction Potential Assessment

The analysis of avoided capacity costs in Table A-5 of the Duke Winter Peak Demand Reduction Potential Assessment contains confidential information that should be protected from public disclosure. Accordingly, I am filing Table A-5 of the Duke Winter Peak Demand Reduction Potential Assessment under seal and request that it be treated confidentially pursuant to N.C. Gen. Stat. § 132-1.2 and protected from public disclosure.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Jack E. Jirak

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of the Tierra and Dunsky Winter Peak Studies, in Docket No. E-100, Sub 165, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 19th day of January, 2022.

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DUKE ENERGY

Winter Peak Targeted DSM Plan

December 2020

DUKE ENERGY

Winter Peak Targeted DSM Plan

December 2020

PREPARED BY:

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Acronyms and Abbreviations

AMI – advanced metering infrastructure

APS – Arizona Public Service

BEopt – Building Energy Optimization Tool (NREL software)

BYO – bring your own

BYO Battery – bring your own battery program

BYOT – bring-your-own smart thermostat program

C&I – commercial and industrial

Connected WH – connected water heater controls program

CPP – critical peak pricing

DEC – Duke Energy Carolinas

DEP – Duke Energy Progress

DER – distributed energy resource

DLC – direct load control

DR – demand response

DSM – demand-side management

EE – energy efficiency

EUL – effective useful life

EV – electric vehicle

EV Manage – electric vehicle workplace/fleet charge management program

EVSE – electric vehicle supply equipment

GETS – grid-interactive electric thermal storage

GW – gigawatt

GWh – gigawatt-hour

HVAC – heating, ventilating, and air conditioning

HWH – hot water heater

IRP – integrated resource plan

ISOP – Integrated System Operations Planning

kW – kilowatt

kWh – kilowatt-hour

LS – load shifting

M&V – measurement and verification

MF – multi-family

MPS – Nexant's Market Potential Study

MW – megawatt

MWh – megawatt-hour

NREL – National Renewable Energy Laboratory

OG&E – Oklahoma Gas & Electric Company

PTR – peak time rebates

RASS – residential saturation survey

RET – rate-enabled smart thermostat program

SF – single family - OR - square foot

SMB – small and medium commercial business

SMUD – Sacramento Municipal Utility District

SRP – Salt River Project

T&D – transmission and distribution

TOU – time of use

TRM – technical reference manual

T-stat – thermostat

Winter HVAC – HVAC comprehensive winter heating efficiency program

1. Introduction and Overview

The Tierra Resource Consultants team with Dunsky and Proctor Engineering as its sub-contractors, is pleased to present to Duke Carolinas (Duke) this Winter Peak Targeted DSM Plan.

Duke Carolinas recognizes that meeting its clean energy commitments requires finding innovative approaches for addressing winter peak capacity needs with clean energy resources. This project is a result of Duke's proactive approach to addressing winter peak, which is becoming a greater need than summer peak as net loads after solar are growing faster for winter needs than summer.

This Plan is the final of three winter peak study reports, including the Winter Peak Analysis and Solution Set study[1] and the Winter Peak Demand Reduction Potential Assessment study[2], on the winter peak capacity needs and potential EE/DSM program opportunities of Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). Duke Carolinas engaged the Tierra team to address winter peak capacity needs, and define a solution set of potential customer rates, initiatives, and DSM customer programs and technologies that together could offer opportunities for Duke to manage energy demand during winter peak periods.

The objective of this plan is to define customer centric winter peak solutions that that can be used to address peak load issues starting in the 2020/2021 winter peak season as well as provide a roadmap for solutions that can be added to the portfolio in the intermediate term, such as advanced rates that effectively aggregate and optimize the impact of grid interactive DER assets. The winter peak targeted solution set, when fully built out over the planning timeframe, is designed to address a significant component of Duke's winter peak capacity needs.

The study finds that distributed energy efficiency and demand side management resources can be utilized in several ways to provide participant benefits while helping to meet Duke's winter peak needs, including:

1) Reducing winter peak load through targeted winter focused energy efficiency (EE) savings,
2) Shifting peak demand through load shifting with flexible distributed energy resource (DER) technologies combined with advanced rate designs, and
3) Clipping peak loads during the highest winter peak demand periods with demand response (DR) programs.

This report, the Winter Peak Targeted DSM Plan, presents a strategic framework and plan for developing a focused solution set of customer programs that drive targeted EE/DR/Flex DER load shape savings impacts to solve near term and longer-term winter peak challenges. The satisfaction of these goals will require the development and delivery of a well-rounded, and integrated set of energy efficiency, demand response, and flexible capacity/load shifting programs and rates.

1.1 Overview of the Winter Peak Targeted DSM Plan Development Process

The development of the Winter Peak Targeted DSM Plan was the third step in a three-step project designed to identify the specific characteristics of Duke's winter peak needs, target the end use loads and customer

[1] Winter Peak Analysis and Solution Set. Tierra Resource Consultants. December 2020

[2] Winter Peak Demand Reduction Potential Assessment. Tierra Resource Consultants. December 2020

segments that are driving Duke's winter peaks, and define a solution set of EE/DSM programs that can help mitigate winter peaks.

In Task 1 of the study, we conducted an analysis of winter peak conditions for the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems. This task culminated in the Winter Peak Analysis report which defines Duke's residential and non-residential customer characteristics (e.g., segmentation) related to winter peak, summarizes residential/non-residential load shapes and winter peak coincident loads, and assesses existing programs, technologies and delivery channels that target key end uses driving winter peak loads.

In Task 2, we identified EE/DSM opportunities and modeled their potential for providing winter peak demand reduction in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems. Building upon the findings from Task 1, the Tierra team evaluated the ability of specific technologies to impact key winter peak coincident end uses that are driving Duke Carolinas system peak, including developing estimated load shape impacts of each potential program. The Winter Peak Demand Reduction Potential Assessment report details the approach and results of this task, which provides insights that can help Duke prioritize winter peak DSM approaches included in this study and in the future.

The final step of the project (Task 3) included the development of this report, the Winter Peak Targeted DSM Plan, which builds upon the findings and observations of the Task 1 winter peak analysis as well as the Task 2 potential modeling work. The task 2 modeling indicated that the greatest winter demand reduction potential exists in the residential sector, with three to four times more total potential than the C&I sector. Within the residential sector, most of the incremental potential can be achieved using new rates and combined with expanded mechanical solutions. These observations informed the program development process.

This project started because of stakeholder input and was developed through a collaborative process between Duke staff, the Tierra team, and interested stakeholders. The process involved information and data exchange, screening of various program concepts, and collaborative discussions about potential solutions. Stakeholder engagement consisted of reviewing all relevant stakeholder comments submitted in Duke's recent Integrated Resource Planning (IRP) process, presenting preliminary results, and receiving input and responding to questions from stakeholders at IRP Stakeholder Forums, Integrated System Operations Planning (ISOP) Forums and EE/DSM Collaborative meetings.[3] A key outcome of this collaboration was the identification of leverage points and areas of coordination with Nexant's DSM Market Potential Study (MPS), assumptions in the integrated resource plan, and load forecast data that helped integrate our winter peak approaches with the big picture.

The identification of solution set concepts that could be applied to meet Duke Carolina's winter peak goals began with the analysis conducted in task 1's Winter Peak Analysis study. This analysis included a review of customer-facing programs and innovative rates currently being developed or deployed by other utilities. Much of this knowledge also originated from the Tierra team's deep experience in distributed energy resource (DER) program design and strategy. This step included various discussions with DSM program managers regarding existing and legacy rates and programs, as well as IRP considerations. These

[3] Stakeholder forums included: 7/18 IRP Stakeholder Forum, 7/23 Carolinas EE/DSM Collaborative

8/21 ISOP Forum, 9/18 IRP Stakeholder Forum, and the 9/30 Carolinas EE/DSM Collaborative discussions helped the project team identify program design parameters and considerations associated with the deployment of these programs in the context of North and South Carolina's regulatory landscapes as well as DEP and DEC's unique system winter peak needs.

Once the review of these programs was completed, the project team assembled a list of potential new programs and rate concepts that could best target winter peak needs. The list was not designed to be comprehensive, but to focus on the highest potential winter peak savings opportunities today as well as tomorrow's emerging technology opportunities that should be proactively addressed now.

The Tierra team met with Duke staff continuously throughout the project to discuss potential solutions and qualitatively screen solution set ideas to assess which opportunities best aligned with Duke's winter peak resource needs. Appendix A ('Programs Considered but Not Included') details the potential solutions that were considered but not selected for inclusion in the plan at this time – these could be opportunities to reconsider in the future. This qualitative screening narrowed the field of candidate programs down to those that most closely met the program selection criteria discussed below, and that could most likely be delivered within DEP and DEC's service territories. The criteria used for the screening process are discussed in the following section.

1.2 Solution Set Screening Approach and Rationale

The process of developing a balanced portfolio of potential winter peak targeted programs began by establishing the design criteria and screening process with which to assess program options and identify those that best align with Duke's resource needs and objectives. Program selection was then a progressive process of screening program concepts against these design criteria, estimating program performance metrics, and developing the basic design elements of each program.

Based on various inputs including Duke's recent DSM Market Potential Study, the resource needs and objectives identified in Duke's Integrated Resource Plan (IRP), discussions with Duke's program managers and related stakeholder comments,[4,5] the project team arrived at the following seven criteria for assessing program options and their potential fit for the targeted solution set:

1. **Target Winter Peak Loads** - Identify DSM opportunities that best align with Duke's winter peak resource needs in terms of the load shape of savings impacts delivered.
2. **Target Technologies Customers are Adopting** - Create customer value by taking advantage of market trends in customer adoption of distributed energy resource (DER) technologies.
3. **Consider Potential Benefits from Combining Innovative Rate Designs and Programs** – Combine DER technologies with smart rate designs that provide ongoing savings for participants.
4. **Leverage Current Duke Programs** - Look for opportunities to 'winterize' programs and take advantage of current delivery channels, platforms, and trade allies to integrate program delivery and add incremental program benefits most cost effectively.

[4] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions on August 27, 2019 Order Docket No. E-100, Sub 157.

[5] State of North Carolina Utilities Commission, Dockett NO. E-100, SUB 157, Order Accepting Integrated Resource Plans and Reps Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses.

5. **Quick Start Opportunities** – Develop specific program plans to acquire winter peak resources identified in the Duke's recent DSM Market Potential Study.
6. **Incremental and Emerging Opportunities** - Identify innovative program designs working in other areas, including emerging opportunities for incremental winter savings potential not identified in the DSM Market Potential Study.
7. **Stakeholder Input** - Carefully consider diverse stakeholder input in developing plans.

Each step in the screening process is further defined in the next section.

1. Targeting Winter Peak Loads

The team spent considerable time understanding the characteristics of Duke's winter peaks to analyze the timing, duration, and coincident customer end uses and segments that most drive Duke's winter peaks to best align potential program savings profiles with Duke's winter peak resource needs.

The team analyzed characteristic winter peak event days and developed breakdowns by segment and end use (where possible) of the contributors to typical winter peak demand. Key takeaways from this step include[6]:

- Winter peak needs are shorter in duration than summer peaks, so they are well suited to being managed with rate innovations, such as TOU or critical peak pricing programs, and DSM /load shifting programs that use control solutions, such as communicating thermostat, to relieve peak conditions.
- When comparing and forecasting net peaks for summer and winter, the growth of large-scale solar generation will result in winter net peaks that are consistently higher than summer. As discussed in the 2020 IRP, new solar resources "economically selected to meet load and minimum planning reserve margin" account for about 1% for winter peak, versus a summer peak range of 10% to 25% of load[7]. This disparity is further defined in the Astrape Study[8] indicating that solar production is a small percentage of nameplate capacity during early morning winter peak periods. The gap between solar production as a winter resource compared to summer is highlighted in the Base Case with Carbon Policy discussion in the 2020 IRP[9], which notes that by 2035 solar only resources (i.e., net of storage) account for 1,232 MW of summer capacity versus 45 MW of winter capacity for DEP[10]and 1,242 MW of summer capacity versus 32 MW of winter capacity for DEC[11]. The resulting potential for resource

[6] Tierra Resource Consultants, Winter Peak Analysis and Solution Set Study.

[7] Duke Energy Carolinas 2020 Integrated Resource Plan. TABLE 12-G, DEC – Assumptions of Load, Capacity, and Reserves Tables

[8] Solar contribution to peak based on 2018 Astrapé analysis

[9] Duke Energy Progress 2020 Integrated Resource Plan, Base with Carbon Policy at page 41

[10] Duke Energy Progress 2020 Integrated Resource Plan. Table 5-A. DEP Base with Carbon Policy Total Renewables

[11] Duke Energy Carolinas 2020 Integrated Resource Plan. Table 5-A. DEC Base with Carbon Policy Total Renewables

gaps is present for both utilities, as shown for DEC in Figure 1[12] and DEP in Figure 2.[13] Higher winter net peaks and the potential for resource gaps support the need for additional winter DSM innovation and resources.

Figure 1. DEC Base Case with Carbon Policy Load Resource Balance (Winter)

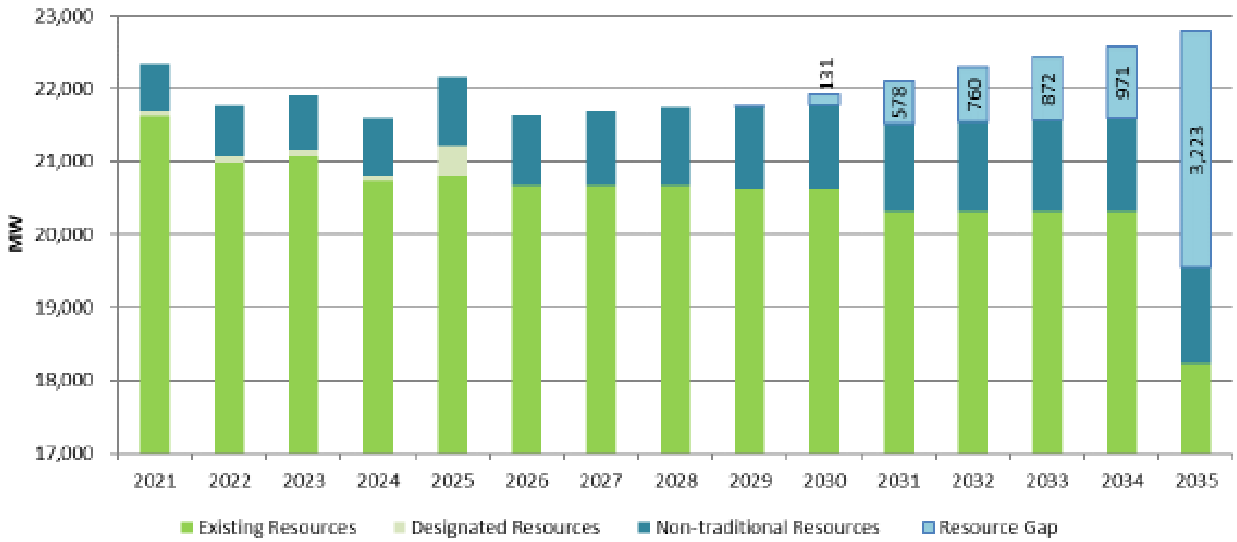
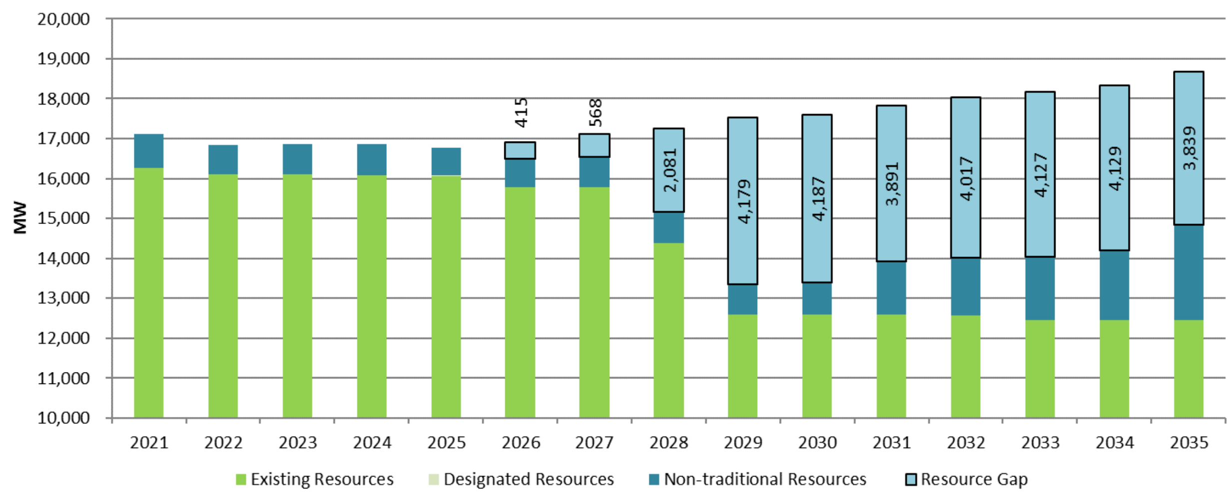


Figure 2. DEP Base Case with Carbon Policy Load Resource Balance (Winter)



- Legacy programs targeting the medium / large C&I sector account for 97% of current total winter DSM capacity and are very cost effective but have limited capacity to deliver additional winter DSM resource as currently configured. In contrast, only 2% of all winter DSM capacity comes from residential DSM programs that operate primarily around Asheville, NC, and less than 1% is contributed through small

[12] Duke Energy Carolinas 2020 Integrated Resource Plan. Figure 12-E DEC Base Case with Carbon Policy Load Resource Balance (Winter)

[13] Duke Energy Progress 2020 Integrated Resource Plan. Figure 12-E DEP Base Case with Carbon Policy Load Resource Balance (Winter)

C&I customers. Conversely, the residential sector accounts for 54% of summer capacity, virtually all of which is driven by controls on air conditioners.

- DSM capacity has grown in EE rider funded programs, though growth may be capped from limited funding resulting from high opt-out rates of the EE rider. Our analysis of opt-out by C&I customers for both DEC and DEP, shows a 50% C&I opt-out based on C&I sales.[14,15] Without a pathway to resolve high DSM opt-out rates for large customers, future growth in Duke's overall DSM capability falls primarily on residential and small to medium size commercial customers.
- Residential all-electric homes with electric space heating are the single biggest end use contributor to winter peaks. Approximately 47% of all heating systems are heat pumps and represent about 80% of electric home demand during peak load periods, with appliances and electric hot water heating accounting for the balance of electric home demand. Electric space heating has three primary subsystems including 1) the heat pump condensers, which makes up the bulk of demand, 2) supplemental heat strips that provide additional heating during cold periods, and 3) the ventilation fans that distributes warm air.
- Winter peaks are primarily driven by residential electric space heating loads and these loads can be difficult to predict because of the way residential heat pumps work during their heating cycle. Heat pumps provide both space cooling and space heating and the condensers work the same in either the heating or cooling mode. However, most heat pumps systems also have supplemental resistance heaters that provide additional heating capacity when a dwelling requires more heat than the condenser can provide. This supplemental resistance heating can increase total heat pump demand by a factor of 3 (e.g., increase from 4 kW to 12 kW for a single home). This is discussed more fully in the Winter Peak Analysis report's section 4, in the discussion on Market Characteristics. In short, the same home equipped with a heat pump might have three times the HVAC load for a few hours in winter as it does during the summer, and while this disparity makes winter peaks harder to predict it is also shorter in duration than summer peak and can be effectively controlled through programmatic solutions.
- The most recent residential appliance saturation survey (RASS) for the Duke Carolinas service territory estimates that 15% of all installed residential thermostats are smart thermostats.
- Overall saturation of Wi-Fi T-stats is 21% but varies by type of heating system, with electric resistance systems having only 7% saturation while stand-alone heat pumps and heat pumps with gas back-up having 24% and 26% saturation, respectively. Saturation also varies by occupant type, where only 4% of renters report having a Wi-Fi T-stat versus 22% of owners.
- Approximately 71% of all hot water heating systems are electric, and hot water heating represents about 10% of electric home demand during peak load periods where appliances and heat pumps are also operating coincident with the water heater.

A thorough understanding of these needs allowed us to consider the load shape of each potential winter peak solution and how well it may be applied to meet Duke's needs. The timing of potential impacts that could be feasibly created with each technology was key to screening for potential rates/program solutions. For more information on this approach, see the Winter Peak Analysis report.

2. Target Technologies Customers Are Adopting

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[14] For 2019 based on Duke Energy Carolinas, LLCDSM/EE Cost Recovery Rider 12 Docket Number E-7 Sub 1230

[15] For 2019 based on Duke Energy Carolinas, LLCDSM/EE Cost Recovery Rider 12 Docket Number E-7 Sub 1230

In this step, the Tierra team looked at national and regional DER adoption trends to target rates and program opportunities that Duke could offer to:

- Help customers adopt the distributed energy resource technologies they want to adopt
- Help them manage those technologies to get the most value out of their energy use
- Help encourage beneficial use of technologies to help meet system goals of clean and reliable energy

This approach benefits participants by enabling customers to adopt new technologies they want at a lower cost through participation in a utility program while also benefitting non-participants by leveraging customer investments in new technologies to help meet Duke's resource needs and clean energy goals most cost effectively.

3. Interaction Between Technologies and Rate Designs

Pairing DER technologies with smart rate design can make it convenient, reliable, and 'automatic' for customers to provide winter peak demand reductions in combination with their rate. When used in conjunction with flexible DER technologies, rate designs can help encourage adoption by providing ongoing bill savings benefits while also driving the beneficial use of these technologies, such as encouraging charging of EVs and batteries during times that benefit all customers rather than on-peak. Accordingly, the solution set was configured to combine good rate options for customers with enabling tools and technologies that can help create integrated smart energy programs that maximize benefits for participants as well as all customers on the grid.

In Staff's comments issued in response to Duke's preliminary IRP,[16] Staff recommended that Duke consider Time of Use rate designs to help manage winter peak needs. This recommendation was confirmed by our analysis of Duke's winter peak resource needs, which indicated that peaks are relatively short in duration compared to summer peaks, making rates and load shifting programs effective tools for managing winter peaks. As a result, the study modeled multiple rate options for residential and commercial customer segments in combination with several different DER technologies to determine how they could interact with the rate designs to drive winter peak focused savings while providing participants with ongoing bill savings.

4. Leverage Current Duke Programs

It is essential that any new winter peak focused program elements are well integrated with Duke's other programs and make sense as part of Duke's overall portfolio of offerings, so the Tierra team spent considerable time understanding Duke's current EE/DSM programs, incentives, delivery channels, and trade ally programs. Wherever possible we considered ways to leverage existing platforms and channels, add elements to 'winterize' existing programs, and add new winter peak focused measures into existing efforts. This lowers total delivery costs while making it easier for customers and trade allies to access programs. As these new programs and technologies are added into Duke's portfolio, it will be important to carefully consider how they fit into Duke's overall program portfolio and customer outreach strategies.

5. Quick Start Opportunities

[16] State of North Carolina Utilities Commission, Dockett NO. E-100, SUB 157, Order Accepting Integrated Resource Plans and Reps Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, page 33.

To address short term winter peak needs in the next two winter peak seasons, the Tierra team identified 'quick start' program opportunities that could begin immediately, starting with the winter peak BYOT smart thermostat demand response program that Duke received approval to start in the winter 2020-2021 season.

An important step in this exercise involved review of Duke's recent EE Market Potential Study to identify some specific technology opportunities and create more detailed winter peak focused program designs and plans for Duke to pursue these programs. It also included identifying quick start opportunities that could expand upon the programs identified in the Market Potential Study, such as the Rate-Optimized Smart Thermostat program for residential and small commercial segments which can enable Duke to rapidly deploy load shifting and demand response capacity in coordination with current and future TOU rates and other innovative rate designs.

6. Incremental and Emerging Opportunities

In this step, the Tierra team identified emerging DER technologies where adoption could impact winter peak needs and where programs could be added to the Duke portfolio in the intermediate term. Intermediate term solutions will likely take time to implement, in some cases requiring regulatory approval for new rates or pilots prior to launching or scaling these efforts.

These solutions focus on proactive approaches to address emerging technologies like EVs and batteries – including coordination between rates and program designs to drive winter peak demand savings. Intermediate term solutions include:

- EV workplace and fleet managed charging to proactively address EV charging behavior and help ensure it does not create morning winter peak demand impacts
- Bring-Your-Own-Battery energy storage program to leverage the opportunity to partner with customers currently adopting this emerging technology
- TOU and TOU+CPP rate designs that could be implemented pending positive results from the Flex Savings Options Pilot conclusions
- Bill-certainty (fixed monthly bill) + PTR and Flat volumetric + CPP rate options to capture the remaining residential winter peak reduction potential

7. Stakeholder Input

Duke's winter peak study was initially pursued because of input from stakeholders, and throughout the process of developing the solution set, the Tierra team reviewed IRP documents, content, input from stakeholders, made presentations at IRP, ISOP and DSM stakeholder collaborative meetings, and responded to stakeholder questions and comments.

Some of the specific feedback we received from stakeholders included:

- Strong support for the winter peak study
- Importance of need to address winter peak issues
- Interest in using TOU and other innovative rate designs as an effective tool to manage winter peak
- Support for clean capacity solutions, and a need for flexible distributed capacity
- Need to consider residential heating solutions, as well as building envelope improvements
- Interest in pursuing emerging DER technologies such as energy storage
- Need to consider options for limited income customers

All the steps outlined above were used to develop a targeted winter peak solution set of rates and EE/DSM program opportunities that best met Duke's resource needs and program design criteria. The next section of this report provides information and a recommended program design framework for each proposed program opportunity.

2. Winter Peak Targeted Rate Designs

This section of the Winter Peak Targeted DSM Plan provides detailed rate design concepts for each new Duke winter peak focused innovative rate opportunity identified as part of this study. These rate design descriptions include basic information for each proposed rate including the overall concept, target market, objectives, incentives and services, marketing and outreach, and delivery strategy. The goal of combining these is to offer a variety of time variant pricing options (e.g., TOU, TOU+CPP, Flat Volumetric + CPP, PTR) that provide customer choice and the ability to reach scale to reduce peak demand and congestion.

This information is intended to inform Duke's development of more detailed rate designs for future filings and implementation plans. The winter peak targeted rate designs include:

- New Time of Use Rate Options ('TOU')
- Critical Peak Pricing ('CPP')
- Bill-Certainty (Fixed Bill Subscription) + Peak Time Rebates ('PTR')

2.1 New Time of Use Rate Options ('TOU')

Table 1. New Time of Use Rate Program Options At-a-Glance

Description	– New series of time of use (TOU) rates should be designed, piloted, and implemented to better enable load shifting and reduced peak demand during winter (and summer) peak periods for residential and small-to-medium business (SMB) customer classes. – Rates will be designed in conjunction with technology-based programs to reduce winter peak. Over time these TOU residential and SMB rates can be coordinated across DEP and DEC service territories in both North and South Carolina. – Rate structures will be designed to encourage customer behavior to avoid adding to peak winter and summer utility grid demand.
Objectives	– Offer customers bill savings opportunities when they shift electricity demand from on-peak to off-peak hours and encourage the use of energy-efficient technologies and controls to reduce peak demand. – Provide time-differentiated pricing options that can reduce both winter and summer peak demand and avert the need for Duke to dispatch or purchase higher-priced generation resources while helping to defer investments in generation and T&D capacity. – Offer a pricing structure that better reflects real time costs of producing and delivering electricity and design rates that encourage customers to learn about demand-shifting behaviors and technologies. – Encourage conservation during peak hours and shift consumption to times when there is excess generation from renewables and other low-carbon generation resources to help meet Duke's clean energy commitment. – Incentivize customers to help them invest in DERs, including smart devices and strategic energy efficiency, which help them to reduce demand more easily and effectively during critical events
Program Intersection with Winter Peak Needs and IRP Filings	– The Duke Carolinas winter peak demand is due primarily to electricity demand patterns in residential and small-to-medium business (SMB) sectors, respectively contributing 53% and 15% of peak. Less than 4% of Duke customers are currently served under time-differentiated rates. – Based on TOU adoption rates in other jurisdictions, we estimate potential for up to 28% of residential customers and 13% of small and medium business customers to opt-in to time differentiated rates within 5 years after the rates are offered[17]. – Public Staff's IRP comments recommend that new TOU schedules have potential to help residential customers curtail loads during winter peaking events. – Higher total demand reduction capacity can be delivered with greater deployment of time-differentiated rate options that better accommodate the customer adoption of emerging energy technologies such as EVs and energy storage. As a result, the structure and expanded adoption of new residential and SMB time-of-use (TOU) rate options will help to meet Duke's need for winter peak reduction by: ○ Diversifying and expanding Duke's DSM resource mix ○ Expanding the DSM market and value proposition ○ Leveraging Duke's emerging data and rate infrastructure ○ Expanding both winter and summer demand response (DR) capacity ○ Reducing the need to purchase expensive wholesale power during peak ○ Avoiding or deferring capacity investments ○ Driving system environmental benefits and helping to meet clean energy commitments through load shifting and storage
Customer Eligibility / Targets	– The primary target markets for the new residential and SMB TOU rate options will include customers: ○ Currently served on a flat volumetric rate who may be interested in the cost benefits that can be delivered by a TOU rate. ○ Open to enrolling in or already enrolled in a TOU rate who may also be willing to do extra to reduce their winter peak demand in return for additional energy cost benefits. ○ Who choose to participate in a technology-based load-shifting program and wish to increase their associated cost savings. ○ Focused on reducing energy costs and willing to shift demand for electricity from peak summer and winter demand periods. – Participation in a new residential or SMB TOU rate should require that customers: ○ Have a standard AMI meter in place. (Duke may install and certify an eligible meter upon customer request to participate.) ○ Are currently enrolled for service under a flat volumetric or existing TOU rate. ○ Stay enrolled in the new TOU rate program for at least one year.
Rate Design	– DEP currently offers standard TOU rate options to SMB commercial customers while DEC does not. Duke should expand the offering of SMB TOU rates that target winter peak hours into the DEC service territories. Both DEP and DEC should offer standard TOU rate options to SMB commercial customers across Carolina territories. – The TOU Rate can be modeled after the North Carolina Flex Savings Options Pilot. Accordingly, the final design of this rate will be informed by final evaluation findings. – Consider increasing the ratio of On-Peak to Off-Peak energy charges for winter season TOU rate periods to be closer to the summer season ratio to provide similar impetus for customers to shift load to reduce the winter peak contribution. – Duke should consider expanding the use of rate structures that include three TOU periods: super off-peak, off-peak, and on-peak. This approach could incent the use load shifting (batteries, thermal storage) and electrification (EVs) technologies and could be used to encourage load shifting to align with renewable energy production to help meet Duke's clean energy commitment. – Duke should offer TOU rate plans that can be combined with smartly designed prepaid energy payments to help customers manage their energy use and create energy and bill savings, while minimizing service disconnections. – We recommend providing TOU rates as part of a suite of rate plans that offer customers multiple options for saving money based on how they would like to manage their energy use.
Required Changes to Tariffs or Rates	– Over time, Residential and SMB TOU rates in DEP and DEC territories should be transitioned to be more consistent across the service territories as much as possible, at least within SC and NC, to enhance simplicity, understanding, and perceived fairness, which will help enable customer acceptance. – Electricity pricing can encourage customers to become active participants in the efforts to keep electricity prices low by empowering them to make informed decisions about their energy usage. Moving more customers to a scenario where electricity costs are time- and location-based will further enable customer engagement in DER markets and cleaner, more efficient utilization of grid resources. – There is enabling regulatory policy needed to unlock the full potential of TOU rates in the Duke Carolinas. Regulatory policy changes that will improve TOU rates include, but are not limited to migration trackers, a decoupling mechanism, and verification of demand reductions.
Market Potential and Participation Goals	– Only ~1% of DEC and 2.8% of DEP residential customers are currently served on a time-differentiated rate. – Based on research into innovative rate options and pilots in other jurisdictions as well as taking into consideration preliminary results not yet made final from Nexant's Flex Savings Options Pilot, the Tierra team's Winter Peak Demand Reduction Potential Assessment report estimates TOU adoption rates for the modeled scenarios will range from 12% to 29% of residential customers across rates.
Marketing Plan	– We assume that TOU rates are proposed as voluntary, opt-in rates. Achieving high customer interest and acceptance will require activity to educate and market to customers. If these rates are proposed under an opt-out scenario in the future, then marketing efforts to enhance customer awareness will become critical to achieving program goals. – Duke will provide customer marketing, education, and outreach to support implementation and engage customers by providing: ○ A menu of multiple but distinct rate options. ○ Clear, easy-to-understand messaging about rate options available. ○ Online tools and calculators to help customers choose their optimal rate. ○ Technical support from staff specifically trained to resolve rate questions.
Energy Impacts and Winter Peak Demand Savings	– The total impact modeled by the Tierra Team under three scenarios indicated the following MW reduction impacts during winter peak. The estimated impact rises from a range of 2.2 to 3.3 MW in 2022 to a range of 61.2 to 81.7 MW by 2030.

2.1.1 Description

A new suite of time-of-use ('TOU') rate options can be designed, piloted, and implemented to better enable load shifting and reduce peak demand during winter (and summer) peak periods for residential and small-to-medium business (SMB) customer classes. These rates should be designed in coordination with DER programs to augment the beneficial impacts of Duke's technology-based programs to reduce winter peak for the Duke Carolinas service territories. Over time these TOU residential and SMB rates should be coordinated as much as possible across DEP and DEC service territories in both North and South Carolina. The rate structures should be designed to facilitate customer behavior that helps defer increases to peak winter (and summer) utility grid demand. We anticipate that the rate design concepts described below will be adapted and refined based on the results of the ongoing North Carolina Flex Savings Options Pilot. [18]

2.1.2 Objectives

The objectives for offering TOU rates that are coordinated with DER programs include:

- Provide customers with an opportunity to save on their energy costs by providing an enhanced incentive through peak hour pricing differentials to shift and stagger their demand for electricity from on-peak to off-peak hours
- Provide time differentiated pricing options that can better reduce both winter and summer peak demand and avert the need for Duke to dispatch or purchase higher-priced generation resources and defer capacity investments in generation and distribution/transmission infrastructure by shifting energy consumption to off-peak times
- Design rates and provide education and tools that encourage customers to adopt demand-shifting behaviors and technologies to reduce peak demand
- Offer a pricing structure that better aligns with the real time costs of producing and delivering electricity year-round
- Encourage conservation during peak hours and shifting consumption to times when there is excess generation from renewables and other low-carbon generation resources
- Incentivize customer investment in DERs, including smart devices, strategic energy efficiency, and energy storage which help them reduce demand easily and effectively during critical events
- Leverage lessons learned from the North Carolina Flex Savings Options Pilot regarding regional event day load impacts, opt-in and opt-out rates, and bill impacts[19]

2.1.3 Program Intersection with Winter Peak Needs and IRP Filings

Duke Carolinas winter peak demand is due primarily to electricity demand patterns in residential and small-to-medium business (SMB) sectors, respectively contributing 53% and 15% of peak. Currently less than 4%

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[17] The Brattle Group. "*Demand Response Market Research: Portland General Electric, 2016-2035*", January 2016. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-02-01-demand-response-market-research.pdf

[18] At the time of this report, the North Carolina Flex Savings Options Pilot was in progress and only limited, preliminary results were available to the Tierra team.

[19] The Nexant *North Carolina Flex Savings Options Pilot Study* is still underway, to date all findings are preliminary and are subject to change.

of Duke customers are served under time-differentiated rates, offering an opportunity to provide winter peak demand savings by increasing the number of customers on TOU rates.

This study details several technology-based programs that are intended to reduce the winter peak, and many of these programs have been designed to be deployed in conjunction with time differentiated rates that provide ongoing bill savings opportunities for customers who deploy load shifting technologies that optimize operation around these rates (e.g., rate enabled thermostats, connected water heating controls). Optimal peak reduction results and customer benefits can be delivered with greater deployment of time-differentiated rate design options that better accommodate the customer adoption of emerging energy technologies such as smart thermostats, digitally communicative appliances, rooftop solar panels, battery storage systems, and electric vehicles.

As a result, the rate structure is designed to address Public Staff's recommendation that Duke investigate the potential for new winter peak focused time-of-use rate designs and contribute to meeting Duke's winter peak reduction needs by:

- Diversifying and expanding Duke's DSM resource mix
- Expanding the DSM market and value proposition
- Leveraging Duke's emerging data and rate infrastructure
- Expanding both winter and summer demand response (DR) capacity
- Providing a pathway for expanded use of existing and emerging technologies
- Reducing the need to purchase expensive wholesale power during peak
- Deferring capacity investments
- Expanding system environmental benefits through load shifting

2.1.4 Customer Eligibility / Targets

The primary target markets for the new residential and SMB TOU rate options will include:

1. Customers that are currently served under a flat volumetric rate who may be interested in the energy cost benefits that can be delivered through a TOU rate
2. Customers who are open to enrolling in or already enrolled in a TOU rate who may also be willing to do extra to reduce their winter peak demand in return for additional energy cost benefits
3. Customers who choose to participate in a technology-based Duke load-shifting or demand response program and wish to increase their associated cost savings
4. Customers who are focused on reducing their energy demand and are willing and able to shift their demand for electricity from peak summer and winter demand periods
5. Customers who purchase smart thermostats, heat pump water heaters or controllers, battery storage and any other relevant technology from the online marketplace.

Participation in a new residential or SMB TOU rate requires that customers:

- Have a standard AMI meter in place (Duke may install and certify an eligible meter upon customer request to participate)
- Are currently enrolled for service under a flat volumetric or existing TOU rate
- Stay enrolled in the new TOU rate program for at least one year

2.1.5 Rate Design

The following residential and SMB TOU rate recommendations are built from the existing TOU rate options that are currently in place in both DEP and DEC territories and are informed by the results of the Winter Peak Study.

TOU Rate Considerations

- DEP currently offers standard TOU rate options to SMB commercial customers while DEC does not. Duke should leverage the focus on winter peak demand to expand the offering of SMB TOU rates into the DEC service territories.
- Both DEP and DEC should offer standard TOU rate options to SMB commercial customers across both North Carolina and South Carolina territories.
- The ratio of On-Peak to Off-Peak energy charges for the winter season for Residential and SMB TOU rates without a demand charge component should at least be increased to equal that of the summer season ratio to provide similar impetus for customers to shift load to reduce the winter peak contribution.
- Duke should consider expanding the use of rate structures that include three TOU periods: super off-peak, off-peak, and on-peak. This approach could incent the use load shifting (batteries, thermal storage) and electrification (EVs) technologies and encourage charging behaviors that align with times when renewable energy is most abundant to help meet Duke's clean energy commitment.
- Based on previous studies, prepay programs have been shown to make customers more aware of the link between their usage and costs, which can result in behavioral energy savings - with some programs demonstrating between 5% and 10% annual energy efficiency savings for customers who participate in prepay offerings. [20] Participating customers benefit from being able to better manage the cost of consumption by monitoring their electricity usage with in-home displays, apps, and/or text alerts that provide ongoing feedback. When combined with education about ways to save energy and take advantage of Duke's EE programs, pre-pay programs can be an effective component of a comprehensive energy efficiency portfolio. Duke could offer TOU rates combined with prepaid energy plans to help customers manage their energy use and create energy and bill savings, especially when paired with rate-enabled DSM technologies like smart thermostats and connected water heaters (described later in this report), that make it easy for customers to have even more control over how they manage their energy costs. Duke should consider piloting this integrated offering to evaluate the extent to which the combination of rates, pre-pay, and DSM technologies can drive customer energy savings and benefits that can be quantified
- Whenever possible, Duke should consider adjusting the on-peak, off-peak, and potentially super-off-peak hours for both summer and winter rate design to focus customers on shorter periods of time for reaction.
- If possible, Duke should consider taking an opt-out approach for certain new TOU rates since this will ensure higher participation levels with less marketing expenditures.

2.1.6 Required Changes to Tariffs or Rates

Over time, Residential and SMB TOU rates in DEP and DEC territories should be transitioned to be more consistent across the services territories, at least within SC and NC, to enhance simplicity, understanding, and perceived fairness, which will help enable customer acceptance. Electricity pricing can encourage customers to become active participants in the efforts to keep electricity prices low by empowering them to make informed decisions about their energy usage. Moving more customers to a scenario where electricity costs are time- and location-based will further enable customer engagement in DER markets and

[20] Claiming Savings from Prepay Programs: Does Prepay Change Behavior and Drive Conservation? E Source.

enable a cleaner, more efficient utilization of grid resources. However, there is enabling regulatory policy still needed to unlock the full potential of TOU rates in the Duke Carolinas. Regulatory policy changes that will improve TOU rates include, but are not limited to:

- Migration trackers to trace the migration of customers among different rates and replacing a deferral account with an adjuster account/charge to enable Duke to adjust in real time and ensure adequate collection of revenues.
- A decoupling mechanism to separate earnings from throughput and make Duke more indifferent to energy efficiency reducing customers' energy consumption.
- Verified demand reduction, to ensure that Duke can receive credit towards its load forecast and realize the value of winter peak savings.

2.1.7 Implementation and Operation

For the deployment of new time variant pricing options, Duke will directly oversee the development of rates. Duke should implement the transition to a larger suite of time-differentiated rate plans with assistance from its existing rate design, implementation, and evaluation contractor partners. To provide synergistic benefits for participants, Duke should encourage the adoption of DER technologies that align with rate plans to make it easier for customers to shift and save. As new rates and programs are launched, Duke should work with local trade allies and community partners to help drive awareness and education about the benefits of participation. This may include for instance the development of an online Energy and Demand Evaluator Tool to help customers learn about the relative energy consumption, demand, and cost impacts of operating common end-use technologies during on-peak and off-peak time periods. Users will better understand how to leverage the rate for their best advantage. A rate comparison tool can also be developed to help customers identify the optimal rate option based on their historical consumption.

2.1.8 Market Potential and Participation Goals

In Duke Carolinas service territory ~1% of DEC and 2.8% of DEP residential customers are currently served on a time-differentiated rate. Based on research into innovative rate options and pilots in other jurisdictions, the Tierra team's Winter Peak Demand Reduction Potential Assessment report estimates TOU adoption rates for the three modeled scenarios will range from 12% to 29% of residential customers across rates, as shown in Table 2.

Table 2.TOU Adoption Rates by Modeling Scenario

	Low Scenario			Mid Scenario			Max Scenario		
Target Rate	DEC RS	DEC RE	DEP Res	DEC RS	DEC RE	DEP Res	DEC RS	DEC RE	DEP Res
TOU	2%	10%	5%	2%	10%	5%	4%	20%	11%
TOU + CPP	10%	15%	12%	10%	15%	12%	6%	9%	7%
Total TOU	**12%**	**25%**	**17%**	**12%**	**25%**	**17%**	**10%**	**29%**	**18%**

2.1.9 Marketing Plan

We have assumed TOU rates are proposed as voluntary, opt-in rates. Achieving high customer interest and acceptance will require activity to educate and market rate options to customers. If these rates could be proposed under an opt-out scenario in the future, adoption rates could be accelerated, and marketing efforts to enhance customer awareness and education about new rates will become more critical to achieving program goals. To quickly expand interest, enrollment, and success with TOU rates Duke should consider building from best-of-class experience of other utilities, including APS, SRP, SMUD, and OG&E that have excelled at gaining customer acceptance of their TOU rate programs and pilots. To achieve relatively high opt-in rates Duke will provide marketing, education, and outreach to support implementation and engage customers by providing:

- A Menu of multiple but distinct rate options including TOU, TOU+CPP, Flat Volumetric + TOU and Bill-Certainty + PTR.
- Limited time bill protections
- Clear, easy-to-understand messaging about available rate options available
- Online tools and calculators to help customers choose the optimal rate for their lifestyle
- Technical support from staff specifically trained to resolve questions about the new rates

Duke should also expand behavioral, education, and outreach to include measurement of load reduced/shifted away from peak so that the impacts of peak reducing rates are recognizable and can be attributed the real benefits they provide to customers.

2.1.10 Measurement & Verification Plan

Evaluation of TOU rates will be key to adjusting and perfecting their design over time. Evaluation efforts should include:

- Tracking opt-in, opt-out, retention and attrition levels
- Establishing a control group that is comparable to the customers enrolled in volumetric rates
- Measuring estimated load impacts and electricity use patterns throughout the day and over time
- Evaluating the performance of different customer segments to shifting load throughout the year and during critical event days, so that they can be compared to DR and CPP program participants
- Continually soliciting customer feedback on rates and marketing through customer surveys

The findings from these evaluation activities will enable Duke to refine outreach and delivery mechanisms as well as inform future rate adjustments to achieve the desired customer peak load reductions during critical events.

2.1.11 Energy Impacts and Winter Peak Demand Savings

The total impact modeled by the Tierra Team under three scenarios indicated the following MW reduction impacts during winter peak. The estimated impact rises from a range of 2.2 to 3.3 MW in 2022 to a range of 61.2 to 81.7 MW by 2030.

2.2 Critical Peak Pricing ('CPP')

Table 3. CPP Program At-a-Glance

Description	– Critical Peak Pricing ('CPP') is a rate rider that can be added onto flat or time of use (TOU) rates. – Participating customers pay a higher price for peak time electricity use (e.g., up to 20 critical events or 140 hours per year) to encourage reductions in peak demand, in exchange for a discount on their standard rate.
Objectives	– Reduce customer bills by rewarding participants who can shift peak-load at critical times to help reduce the cost of service – Offer price signals that better align with the real time costs of producing and delivering electricity. – Reduce peak demand and congestion, help avert the need to dispatch higher-priced generation and help lower wholesale market prices. – Defer capital investments in generation capacity as well as distribution and transmission infrastructure by shifting energy consumption to off-peak times. – Incent customers to invest in DERs, including smart devices and strategic energy efficiency, which help them reduce demand more easily and effectively during critical events.
Program Intersection with Winter Peak Needs and IRP Filings	– Critical peak pricing offers a tool for Duke to help manage critical winter peak events through price signals that encourage demand response and energy efficiency during critical peak times. – As Duke's DSM capability is currently configured, growth in overall DSM capability falls primarily on residential customers because legacy programs have limited growth potential and DSM rider opt-out occurs primarily among large C&I customers. This is consistent with Public Staff's IRP comment that new TOU schedules have the greatest potential to help residential customers curtail loads during winter peaking events.
Customer Eligibility / Targets	– The primary target markets for Critical Peak Pricing will consist of: ○ Customers currently enrolled in a flat volumetric rate who may not be interested in having to manage their daily demand on a TOU rate but are willing to curtail demand occasionally during critical events. ○ Customers open to enrolling in or already enrolled in a TOU rate who may also be willing to do extra to reduce their demand on critical peak days.
Rate Design	– The rate design structure consists of two options, Flat Volumetric + CPP and TOU + CPP. – The CPP Rate Rider can be modeled after the North Carolina Flex Savings Options Pilot. Accordingly, the final design of this rider will be informed by final evaluation findings. ○ Customers will pay a higher rate, currently $.40/kWh, during on-peak hours on critical event days for up to 20 days or approximately 140 hours each year in exchange for a 10% discount on the standard rate for their class.
Required Changes to Tariffs or Rates	– CPP will require revisions to Duke's North Carolina Residential Schedules RS-CPP, RE-CPP, RS-TOU-CPP and RE-TOU-CPP as necessary according to the final findings and recommendations of the Flex Savings Options Pilot study currently underway. – Duke should file similar CPP pilot rates in South Carolina as are currently being tested in North Carolina's Flex Savings Options Pilot, including a RES-CPP and RES-TOU-CPP rate.
Market Potential and Participation Goals	– Based on research into innovative rate options and pilots in other jurisdictions, we estimate that CPP adoption rates for the modeled scenarios, including both TOU + CPP and Flat Volumetric + CPP, will range from 10% to 20% of residential customers across rates.
Marketing Plan	– Duke will provide customer marketing, education, and outreach to support large-scale implementation and engage customers by providing: ○ A menu of multiple but distinct rate options. ○ Clear, easy-to-understand messaging about rate options available. ○ Online tools and calculators to help customers choose their optimal rate. ○ Technical support from staff specifically trained to resolve rate questions. ○ Focus groups or surveys of customers currently participating in the Flex Savings Options Pilot to assess whether customers understand the proposed rate, gauge interest, and better understand barriers to adoption prior to full-scale rollout.
Energy Impacts and Winter Peak Demand Savings	– The Tierra team found that the CPP rate option could deliver between 7 and 18 MW of peak reduction by winter 2022 and between 425 and 460 MW by 2041. – In the low scenario, which examined DSM potential from the TOU and TOU+CPP rate options evaluated under the Flex Savings Options Pilot, the CPP rate option accounted for 60% of the customer enrollment and about 85% of the residential DSM rate savings, providing significantly higher savings per customer than TOU. – In the Max scenario which assessed a complete set of residential rates options ranging from low risk (Bill-certainty with PTR) to high risk (TOU+CPP), the CPP rate options accounted for approximately 47% of the overall DSM rates savings. – Based on these findings the CPP rate option, particularly TOU+CPP which accounted for 266 MW or 28% of the overall DSM rates savings, is key to achieving significant winter demand reduction potential.

2.2.1 Description

The Critical Peak Pricing (CPP) Rate Rider is a dynamic overlay option for Duke's residential electric service, including both its existing flat volumetric rates as well as its existing and newly proposed time-of-use (TOU) rates. This time variant pricing option would allow Duke to call critical events up to 20 times per year based on system conditions such as when there is expected to be extreme temperatures, high energy usage, high market energy costs, or major generation or transmission outages. Customers enrolled in this add-on rate rider will be alerted the day before a critical event and agree to pay a higher price for peak time electricity use during these critical events, encouraging reductions in demand, in exchange for a discount on their standard rate. CPP will be offered to qualified residential customers on a flat volumetric or TOU rate on a voluntary basis. CPP will not be available to customers enrolled in peak time rebates (PTR) or demand response programs because Duke already is providing these customers incentives in exchange for direct load control. Customers who enroll in CPP and do not currently own a smart thermostat can be channeled into the newly proposed Rate-Enabled Smart Thermostat Program to receive a free smart thermostat that will enable them to respond to TOU prices and/or CPP events through rate enabled load shifting.

2.2.2 Objectives

The CPP Rate Rider is a new residential rate structure that will promote peak load reductions during critical events in the winter and summer seasons.

The objectives for implementing this program include:

- Lower customer bills by providing the education and tools necessary to shift peak-load and rewarding participants who can manage peak demand at critical times to lower the cost of service.
- Offer prices that better align with the real time costs of producing and delivering electricity.
- Provide multiple time variant pricing options (e.g., TOU, TOU+CPP, Flat Volumetric + CPP, PTR) that with scale can reduce peak demand and congestion and help avert the need to dispatch higher-priced generation or wholesale market purchases.
- Defer investments in generation capacity as well as distribution and transmission infrastructure by shifting energy consumption to off-peak times and specifically targeting critical peak hours.
- Encourage conservation and shifting energy use to times when there is excess generation from renewables to help meet clean energy goals.
- Incent customer investment in DERs, including smart devices and strategic energy efficiency, which help them to reduce demand more easily and effectively during critical events.
- Encourage CPP participants to adopt free smart thermostats which has been shown to substantially increase CPP critical event peak demand reductions.[21]
- Leverage lessons learned from the North Carolina Flex Savings Options Pilot regarding regional event day load impacts, opt-in and opt-out rates, and bill impacts.[22]

2.2.3 Program Intersection with Winter Peak Needs and IRP Filings

The winter peak characterization that was conducted as part of this study indicates that as Duke's DSM capability is currently configured, growth in overall DSM capability falls primarily on residential and small

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[21] US Department of Energy *Final Report on Impacts from the Consumer Behavior Studies*, November 2016.

[22] The Nexant *North Carolina Flex Savings Options Pilot Study* is still underway, to date all findings are preliminary and are subject to change.

to medium size commercial customers because legacy programs have limited growth potential and DSM rider opt-out occurs primarily among large C&I customers. This is consistent with Public Staff's IRP comment that new TOU schedules have potential to help residential customers curtail loads during winter peaking events.[23] Accordingly, the CPP rate structure addresses Public Staff's recommendation that Duke investigate the potential for new winter peak focused TOU rate designs and contribute to meeting Duke's Winter Peak needs by:

- Diversifying and Expanding its DSM Resource Mix
- Expanding the DSM Value Proposition
- Expanding the DSM Market
- Leveraging Duke's Emerging Data and Rate Infrastructure
- Expanding both Winter and Summer Demand Response Capacity
- Providing a Pathway for Expanded Use of Existing and Emerging Technologies

Currently approximately 99% of residential customers are on flat rates with approximately 97% of DEP customers on a flat rate and 3% on TOU rates while less than 1% of DEC customers are on a TOU rate with the remaining customers on either an all-electric or dual fuel flat rate. Given these considerations, the CPP Rate Rider is flexible enough that, unlike the newly proposed Peak Time Rebate, both most customers on a flat rate as well as those early adopters of TOU rates can enroll.

2.2.4 Customer Eligibility / Targets

The primary target markets for CPP Rate Riders will consist of:

1. Customers currently enrolled in a flat volumetric rate who may not be interested in having to manage their daily demand on a TOU rate but are willing to curtail demand occasionally during critical events. These consumers can change their load in a significant manner but are not willing to modify their everyday usage (i.e., flat volumetric + CPP).
2. Customers open to enrolling in or already enrolled in a TOU rate who may also be willing to do extra to reduce their demand on critical peak days. These consumers are highly attentive to their energy demand and can change their load in a significant manner (i.e., TOU + CPP).
3. Customers who purchase smart thermostats, heat pump water heaters or controllers, battery storage and any other relevant technology from the online marketplace.

To participate in this rate rider, customers:

- Must have a standard AMI meter in place. Duke may install and certify an eligible meter upon customer request to participate.
- Must be enrolled in a flat volumetric or TOU rate.
- Must not be enrolled simultaneously in the PTR rate rider or another demand response program.
- Must stay enrolled in the rider for at least one year.

2.2.5 Rate Design

The CPP Rate Rider as described below is modeled after the North Carolina Flex Savings Options Pilot. Accordingly, the final design of this rider should be informed by the final evaluation findings.

[23] State of North Carolina Utilities Commission, Dockett NO. E-100, SUB 157, Order Accepting Integrated Resource Plans and Reps Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, page 33.

The rate design structure for the CPP Rate Rider consists of two dynamic overlay options, Flat Volumetric + CPP and TOU + CPP. For both options customers will pay a higher rate, currently \$.40/kWh,[24] during on-peak hours on critical event days for up to 20 days or approximately 140 hours each year in exchange for a 10% discount on the standard rate for their class. The number of critical event days permitted annually may be exceeded in the event of a system emergency that is expected to place Duke's ability to provide reliable service to customers at risk. CPP events will only be scheduled as follows:

- 6:00 a.m. to 10:00 a.m. plus 6:00 p.m. to 9:00 p.m. Monday through Friday, excluding holidays during the winter season.
- 2:00 p.m. to 8:00 p.m. Monday through Friday, excluding holidays during the summer season.

Duke will use its best efforts to notify customers by 4:00 p.m. on the prior day for critical event days, however, notification of critical event days can occur at any time, but no later than one hour prior to the on-peak period. The customer will receive a phone message, e-mail, or text message notification of upcoming event days and is responsible to watch for this message. Once noticed, a CPP event will not be cancelled.

3.2.6 Required Changes to Tariffs or Rates

The CPP Rate Rider will require revisions to Duke's North Carolina Residential Schedules RS-CPP, RE-CPP, RS-TOU-CPP and RE-TOU-CPP as necessary according to the final findings and recommendations of the Flex Savings Options Pilot study currently underway by Nexant. Additionally, Duke will file in South Carolina similar CPP pilot rates as are currently being tested in North Carolina's Flex Savings Options Pilot, including a RES-CPP and RES-TOU-CPP rate.

2.2.7 Implementation and Operation

For the deployment of new time variant pricing options, including CPP, Duke will directly oversee the development of rates. Duke should develop, market and administer the CPP rider with assistance from its existing rate design, implementation, and evaluation contractor partners. Key operational activities include project management, call center operations, daily website updates, and deployment of customer notifications. Duke should leverage its existing infrastructure, such as that used in the Flex Savings Options Pilot, for notifying customers of critical event days. Prior to rolling out these rates across the Carolinas, Duke should assess the team responsible for handling notifications and customer outreach to ensure that there are adequate resources to monitor the accuracy and performance of vendor systems in real time as well as support increased call volume resulting from the price change and installation issues related to new smart thermostats and meters.

2.2.8 Market Potential and Participation Goals

Based on research into innovative rate options and pilots in other jurisdictions, the Tierra team's Winter Peak Demand Reduction Potential Assessment report estimates that CPP adoption rates for the modeled scenarios, including both TOU + CPP and Flat Volumetric + CPP, will range from 10% to 20% of residential customers across rates, over the study period ending 2041. Table 4 details the adoption rates for TOU + CPP and Flat Volumetric + CPP by modeling scenario and rate.

[24] Duke Energy Residential Schedules RS-CPP, RE-CPP, and RE-TOU-CPP effective 6.1.2020.

Table 4. CPP Adoption Rates by Modeling Scenario

	Low Scenario			Mid Scenario			Max Scenario		
Target Rate	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**
TOU + CPP	10%	15%	12%	10%	15%	12%	6%	9%	7%
Flat Volumetric + CPP	-	-	-	-	-	-	4%	11%	7%
Total Market	**10%**	**15%**	**12%**	**10%**	**15%**	**12%**	**10%**	**20%**	**14%**

2.2.9 Marketing Plan

Since CPP will be a voluntary or opt-in rate, marketing and customer education is crucial to achieving program enrollment targets. Prior to territory wide rollout of the rate rider, Duke will conduct additional market research to assess whether customers understand the proposed rate, gauge interest, and better understand barriers to adoption to develop the best methods for enrollment. This could be done through focus groups or surveys of customers currently participating in the North Carolina Flex Savings Options Pilot. To achieve relatively high opt-in rates, Duke will provide customer marketing, education, and outreach to support implementation and engage customers by providing:

- A Menu of multiple but distinct rate options including TOU, TOU+CPP, Flat Volumetric+TOU and Bill-certainty+PTR.
- Offering limited time bill protections
- Clear, easy-to-understand messaging about available rate options available
- Online tools and calculators to help customers choose the optimal rate for their lifestyle
- Technical support from staff specifically trained to resolve questions about the new rates

Duke should also expand behavioral, education, and outreach to include measurement of load reduced/shifted away from peak so that the impacts of peak reducing rates are recognizable and can be attributed the real benefits they provide to customers.

2.2.10 Measurement & Verification Plan

Evaluation of the CPP Rate Rider will be key to adjusting and perfecting CPP over time. Evaluation efforts should include:

- Tracking retention and attrition levels over time
- Establishing a control group that is comparable to the customers enrolled in CPP
- Evaluating load impacts and estimating enrolled customers’ electricity use patterns throughout the day and over time
- Assessing different customer segments’ responsiveness to calling critical event days
- Continually soliciting customer feedback on rates and marketing through customer surveys

The findings from these evaluation activities will enable Duke to refine outreach and delivery mechanisms as well as inform future rate adjustments to achieve the desired customer peak load reductions during critical events.

2.2.11 Energy Impacts and Winter Peak Demand Savings

The Tierra team's modeling results, detailed in the Winter Peak Demand Reduction Potential Assessment, found that the CPP rate option could deliver between 7 and 18 MW of peak reduction by winter 2022 and between 425 and 460 MW by 2041. In this report's low scenario, which examined DSM potential from the TOU and TOU+CPP rate options evaluated under the Flex Savings Options Pilot, the CPP rate option accounted for 60% of the customer enrollment and about 85% of the residential DSM rate savings, providing significantly more savings per customer than TOU. These high savings from CPP participants are consistent with the preliminary results from the Flex Savings Options Pilot. For comparison, in the Max scenario which assessed a complete set of residential rates options ranging from low risk (Bill-certainty with PTR) to high risk (TOU+CPP), the CPP rate options accounted for approximately 47% of the overall DSM rates savings. Based on these findings the CPP rate option, particularly TOU+CPP which accounted for 266 MW or 28% of the overall DSM rates savings, is key to achieving significant winter demand reduction potentials.

2.3 Bill-Certainty ('Fixed Bill Subscription') + Peak Time Rebates ('PTR')

Table 5. Bill-Certainty + Peak Time Rebates Program At-a-Glance

Description	– Peak Time Rebates ('PTR') is a is time variant pricing option that encourages reductions in peak demand by providing customers with a rebate for each kWh they shed relative to their customer specific baseline usage during up to 20 critical events or 140 hours per years. – In the proposed rate design, the underlying tariff for residential and small C&I customers must be a subscription plan with a fixed monthly bill (i.e., Bill-Certainty). This subscription plan will allow the customer to swap their volumetric price risk in exchange for a fixed monthly bill where the price is customized to each customer based on historic usage and selected perks (e.g., 100% clean or renewable energy, more or less connected devices enrolled in DR, etc.). Customers will be outfitted with DSM technologies such as smart thermostats and smart water heaters or water heater controllers and will save more, the more they allow Duke to co-manage these types of grid-interactive devices. – Large C&I customers may enroll while being on any existing C&I rate. – Customers who do not achieve a measurable reduction of electricity usage will not be assessed any penalties.
Objectives	– Reduce customer energy costs by educating customers about demand response and encouraging savings on peak days. – Incentivize customers who are risk-adverse or unable to shed consumption at a particular time to participate in helping to reduce peak demand when they can, without the risk of increased bills when they can't. – Attract participation from large C&I customers, which historically have had high DSM Rider opt-out rates. – Providing more efficient technologies and appliances as well as guaranteed rates to budget-minded, fixed-income, low-moderate income, and small businesses customers through a fixed-bill subscription plan offering. – Offering customers, the simplicity and convenience of standard fixed-bill pricing through a subscription plan, while also allowing them to share in some of the cost savings achieved from peak reductions.
Program Intersection with Winter Peak Needs and IRP Filings	– PTR is designed to offer large C&I customers a win-win situation by allowing them to stay on their existing rate and receive rebates for reducing demand without risk of being penalizing if a critical event occurs during a period in which they are unable to reduce demand. Large C&I customers would likely not be offered a fixed bill subscription rate. – Duke can use the addition of the PTR rate to encourage large C&I customers to consider opting back into the EE rider, which would increase DSM funding. Approximately 50% of C&I GWh are from companies that have opted-out of the EE rider and thus cannot participate in DSM offerings; primarily driven by high EE rider opt-out rates for large customers.
Customer Eligibility / Targets	– The primary target markets for the subscription plan will include budget-minded, fixed-income, low-moderate income, and small businesses customers who will benefit from a guaranteed rate or are wat to adopt grid-interactive technologies. – The primary target markets for PTR will consist of: 1) Residential and small C&I customers who are not interested in having to manage their daily demand on a TOU rate and are risk averse to the higher peak-time pricing of CPP but are willing to curtail demand occasionally during critical events. 2) Large C&I customers, particularly those that have not opted out of the EE Rider or are sensitive to potential production interruptions from demand response, who may be attracted to a more flexible option for participating in demand response events than existing and legacy DSM offerings. – Participating residential and small C&I customers must be enrolled in a Bill-certainty/fixed bill subscription plan. Medium and large C&I customers can overlay the PTR on any existing Duke C&I tariff. – PTR participants cannot be enrolled simultaneously in another demand response program.
Rate Design	– The rate design structure for PTR consists of 1) Bill-certainty + PTR for residential and small C&I customers and 2) C&I Rate + PTR for Medium and large C&I customers. – The benefit of combining the subscription plan and PTR is that it simplifies billing for customers while eliminating the risk of non-performance during critical event demand response and TOU peak demand. This is often a concern for customers in more complex TOU and CPP rates, especially fixed-income customers who typically can't afford to pay a higher rate during these periods. The subscription plan and PTR combination balances straightforward billing and demand savings by offering customers a guaranteed monthly bill with built-in energy savings from daily load shifting provided from co-management of grid-interactive devices with Duke. – The rebate for Residential and small PTR would be set at a 3:1 savings ratio for all rates while the medium and large C&I PTR will offer between \$.30 and \$.90/kWh. Rebates will occur as a credit on customer bills and will include documentation of the date of the event, kWh reduction, and credit amount.
Required Changes to Tariffs or Rates	– Requires approval of new underlying rate plans (bill certainty) as well as the PTR rider framework.
Market Potential and Participation Goals	– Based on research into innovative rate options and pilots in other jurisdictions, the Tierra team's Winter Peak Demand Reduction Potential Assessment report estimates that Bill Certainty + PTR adoption rates will range from 8% to 25% of residential customers depending on the modeling scenario and rate. – For small C&I customer adoption levels, the team modeled three scenarios with adoption levels ranging from 10% to 20%. For the medium and large C&I PTR rate, the model determined the expected maximum program participation based on the incentive offered, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves. The propensity curve was calibrated to the existing participation level from DRA and PowerShare. The incentive level used in the model to determine Medium & Large C&I participation ranged from \$30/kW/year to \$90/kW/year.
Marketing Plan	– Duke will provide customer marketing, education, and outreach to support implementation and achieve high opt-in rates. – Duke should engage customers by providing a menu of multiple but distinct rate options, easy-to-understand messaging about available rate options, online tools and calculators, and technical support from staff trained to resolve questions.
Energy Impacts and Winter Peak Demand Savings	– The Tierra team's modeling results found that the PTR rate options could deliver between 9.3 and 18.2 MW of peak reduction by winter 2023 and between 149.9 and 407.9 MW by 2041. – PTR rate options accounted for 43% of the overall proposed rates savings, of which the Bill-certainty + PTR option accounted for 236 MW or 25% of the overall rates savings. Based on these results, PTR is an important component of achieving Duke Carolina's winter demand reduction potentials in both the residential and commercial sector. – The modeling results of the Mid and Max scenarios found that an increase in adoption among small C&I customers and an increase in PTR incentives for the medium and large C&I customers resulted in limited additional uptake.

2.3.1 Description

The Peak Time Rebate (PTR) is a dynamic optional rate rider for both residential and non-residential customers. This time variant pricing option allows Duke to call critical events up to 20 days per year based on forecasted system conditions such as extreme temperatures, high energy usage, high market energy costs, or major generation or transmission outages. Customers will be alerted the day before a critical event and will receive a rebate for each kWh they shed during the critical event relative to their customer specific baseline usage. Customers who do not achieve a measurable reduction of electricity usage will not receive any rebates and they will not be assessed any penalties. Unlike CPP, customers will not receive a discount during off-peak periods and are instead on a fixed monthly bill.

In the proposed rate design, the underlying tariff for residential and small C&I customers must be a subscription plan with a fixed monthly bill (i.e., Bill-Certainty). This subscription plan will allow the customer to swap their volumetric price risk in exchange for a fixed monthly bill where the price is customized to each customer based on historic usage. The plan can be designed to not only provide a guaranteed monthly rate, but to help co-invest in efficiency improvements and grid-interactive devices that expand flexible demand potential while providing customer savings and benefits. Customers who participate could be outfitted with DSM technologies such as smart thermostats and connected water heating controls at no upfront cost with options for greater savings the more they allow Duke to co-manage these grid-interactive devices. The program could target budget-minded, fixed-income, low-moderate income, and small businesses customers to expand total market potential by offering a unique program design for harder to reach customers who might not be able to participate in other programs. These customers can benefit from receiving newer, more efficient technologies and appliances as well as the assurance of a fixed bill each month. This design can benefit all Duke customers by helping to keep rates low by reducing cost of service for participants. While there is some risk associated with overconsumption this risk is absorbed by shareholders and minimized through co-management of connected technologies installed, which help manage the peak energy consumption and demand of customer's two largest loads, HVAC and water heating.

Large C&I customers can enroll while being on any existing C&I rate. Large C&I customers would likely not be offered a fixed bill subscription rate. For the C&I market, PTR is a qualifying rate that allows customers who are enrolled in the DSM rider to participate in the ADR program.

For the residential market PTR cannot be combined with DR device programs such as BYOT or CPP because this would result in customers receiving incentives twice to curtail the same load. The PTR program is designed to reward customers who provide peak demand behavioral (non-device) savings on event days but who do not want to participate in a direct load control program or CPP/TOU rate.

2.3.2 Objectives

The PTR Rate Rider is a new residential and commercial rate structure that will promote peak load reductions year-round during critical events. The rationale for implementing this program includes:

- Helping to reduce customer bills through PTRs and educating customers about demand response and encouraging peak demand savings on peak days
- Incentivizing customers who are risk-adverse or unable to shed consumption at a particular time to participate in demand response events without the risk of increased bills
- Attracting participation from large C&I customers, who have historically high DSM Rider opt-out rates.
- Offering another variation to the suite of multiple time variant pricing options (e.g., TOU, TOU+CPP, Flat Volumetric+CPP, PTR) that with scale can reduce total system peak demand

- Deferring investments in generation capacity as well as distribution and transmission infrastructure by shifting energy consumption to off-peak times
- Providing more efficient technologies and appliances as well as guaranteed rates to budget-minded, fixed-income, low-moderate income, and small businesses customers through a fixed-bill subscription plan offering.
- Offering customers the simplicity and convenience of standard fixed-bill pricing through a subscription plan, while also continuing to encourage customers to conserve energy during critical event days and letting them share in some of the cost savings achieved from peak reductions.

2.3.3 Program Intersection with Winter Peak Needs and IRP Filings

The winter peak characterization that was conducted as part of this study found that 50% of C&I GWh sales are to companies that have opted-out of the EE rider and thus cannot participate in DSM offerings. The characterization assessment found that nearly 100% of larger customers in DEP opt-out of the EE rider. The Tierra team's impression is that the EE rider funded programs targeting the large C&I market currently offer limited value to customers who 1) do not have significant backup generation or 2) do not have process loads that can be easily curtailed. Duke's DSM solution for Large C&I customers relies mostly on the use of customer-sited backup generation and process interruptions which suffer from the following shortcomings:

- The backup generation market is limited and may not be growing as industrial loads decline, and the potential that may exist is likely to have been recruited through the legacy and EE rider programs in operation over the past decade. This potential is also at risk because it is subject to regulatory constraints outside of Duke's control, such as limitations on backup generation operating hours.
- Commercial demand response capacity related to production interruptions is less reliable because it is unlikely to respond during multiple concurrent winter peak days, such as a polar vortex. As a result of concerns about customer impacts, this resource has been generally restricted to infrequent use and does not provide substantial system planning or economic benefit to Duke.
- Fossil back-up generators are not well aligned with Duke's zero net emission by 2050 target.

The rate structure of PTR is designed to offer large C&I customers a win-win situation by allowing them to stay on their existing rate and receive rebates for reducing demand without risk of being penalizing if a critical event occurs during a period in which they are unable to reduce demand due to process limitations. Duke can use the addition of the PTR rate to help encourage large C&I customers to opt back into the EE rider, which would increase DSM funding.

2.3.4 Customer Eligibility / Targets

The primary target markets for the subscription plan will include budget-minded, fixed-income, low-moderate income, and small businesses customers who would benefit from a guaranteed monthly rate or are interested in receiving free or incentivized grid-interactive technologies (e.g., smart thermostats, water heaters or controllers, etc.).

The primary target markets for PTR will consist of:

1. Residential and small C&I customers who are not interested in managing their daily demand on a TOU rate and are risk averse to the higher peak-time pricing of CPP but are willing to curtail demand occasionally during critical events and find a fixed monthly bill attractive. These consumers can provide valuable savings from shedding load during some critical events.
2. Large C&I customers, particularly those that have opted out of the EE Rider or are sensitive to production interruption, who will be attracted to a more flexible option for participating in demand response events than existing and legacy DSM offerings.

To participate in the PTR rate, customers must:

- Have a standard AMI meter in place (Duke may install and certify an eligible meter upon customer request to participate)
- In the proposed rate design, participating residential and small C&I customers must also be enrolled in a Bill-certainty rate. Medium and large C&I customers can overlay the PTR on any existing Duke C&I tariff.
- Participating customers cannot be enrolled simultaneously in a TOU, CPP, or a demand response program including programs, such as the Rate Enabled Smart Thermostat program and must stay enrolled in PTR for at least one year.
- For the C&I market, PTR is a qualifying rate[25] that allows customer who are enrolled in the DSM rider to participate in the ADR program and receive incentives for equipment, such as EMS, that enables participation in PTR.

2.3.5 Rate Design

The rate design structure for PTR consists of:

1. Bill-certainty + PTR for residential and small C&I customers
2. C&I Rate + PTR for medium and large C&I customers

Medium and large C&I customers may overlay the PTR on any existing Duke C&I tariff. The underlying tariff for residential and small C&I customers must be a flat (i.e., fixed) monthly bill for energy use where the price is customized to each customer based on historic usage and selected perks (e.g., 100% clean or renewable energy, more or less connected devices enrolled in DR, etc.). Embedded in the customer's fixed price is a risk premium, likely based on a function of marginal costs, to compensate Duke for taking on the risk that a customer's consumption will exceed expectations. Bill-certainty contracts will lock in energy prices for a minimum of 12 months but may be locked in for a longer term. There are no true-up settlement or deferred payments at the conclusion of the contract.

The benefit of combining the subscription plan and PTR is that it simplifies billing for customers while eliminating the risk of non-performance during critical event demand response and TOU peak demand. This is often a concern for customers in more complex TOU and CPP rates, especially fixed income customers who typically can't afford to pay a higher rate during these periods. The subscription plan and PTR combination balances straightforward billing and demand savings by offering customers a guaranteed monthly bill with built-in energy savings from daily load shifting provided from co-management of grid-interactive devices with Duke. With Bill-certainty + PTR, Duke can offer customers the simplicity and convenience of standard fixed-bill pricing while also continuing to encourage customers to conserve energy during critical event days by sharing some of the cost savings achieved from winter and summer peak reductions through the PTR. A residential and small C&I customer Bill-Certainty rate will also benefit Duke's system by providing an opportunity to better align fixed supply costs, including transmission and distribution capacity costs as well as increasingly fixed generation costs from the growth of renewables, with fixed revenue.

[25] PTR is not the only qualifying rate for ADR, for example, existing TOU rates as well as other C&I rates that become available in the future.

The PTR overlay rewards customers for each kWh they reduce on critical event days compared to their established custom baseline. A baseline for each Critical Event Day will be calculated using customer specific load for recent historical non-event, non-holiday weekdays similar in temperature and humidity. The PTR for Residential and small C&I would be set at a 3:1 savings ratio for all rates[26] while the medium and large C&I PTR will offer between $.30 and $.90/kWh. Rebates will occur as a credit on customer bills and will include documentation of the date of the event, kWh reduction, and credit amount.

Duke may call up to 20 critical event days or approximately 140 hours each year. The number of critical event days permitted annually may be exceeded in the event of a system emergency that is expected to place Duke's ability to provide reliable service to customers at risk. PTR events may be scheduled as follows:

- 6:00 a.m. to 10:00 a.m. plus 6:00 p.m. to 9:00 p.m. Monday through Friday, excluding holidays during the winter season.
- 2:00 p.m. to 8:00 p.m. Monday through Friday, excluding holidays during the summer season.

Duke will use its best efforts to notify customers by 4:00 p.m. on the prior day for critical event days, however, notification of critical event days can occur at any time, but no later than one hour prior to the on-peak period. The customer will receive a phone message, e-mail, or text message notification of upcoming event days and is responsible to watch for this message. Once noticed, a PTR event will not be cancelled.

Both residential and small C&I as well as large C&I customers are attracted to PTR rates because unlike CPP, the customer bares no risk of increased price if they are unable to reduce consumption during a critical event. PTR is a way for Duke to expand the number of participants in time variant rates by providing risk adverse customers who would otherwise choose not to participate, a more flexible rate option for reducing winter peak demand.

2.3.6 Required Changes to Tariffs or Rates

Implementation will require approval of the underlying bill certainty rate riders for residential and small business customers, as well as the PTR tariff framework.

2.3.7 Implementation and Operation

For the deployment of new time variant pricing options, including PTR, Duke will directly oversee the development of rates. Duke should plan to develop, market and administer the PTR rider with assistance from its existing rate design, implementation, and evaluation contractor partners. Key operational activities include project management, call center operations, daily website updates, and deployment of customer notifications. Duke should leverage its existing infrastructure, such as that used in the Flex Savings Options Pilot, for notifying customers of critical event days. Prior to rolling out these rates across the Carolinas, Duke should assess the team responsible for handling notifications and customer outreach to ensure that there are adequate resources to monitor the accuracy and performance of vendor systems in real time as well as support increased call volume resulting from the price change and installation issues related to new smart thermostats and meters.

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[26] For example: With an average cost of electricity over the fixed bill is 15¢/kWh, the rebate would be 30¢/kWh, for a total discount of 45¢/kWh, which is three times to initial cost of electricity.

2.3.8 Market Potential and Participation Goals

Based on research into innovative rate options and pilots in other jurisdictions, the Tierra team's Winter Peak Demand Reduction Potential Assessment report estimates that Bill Certainty + PTR adoption rates for the modeled scenarios will range from 8% to 25% of residential customers across rates. Table 6 details the adoption rates for Bill Certainty + PTR by modeling scenario and rate.

Table 6.Residential Bill-Certainty + PTR Adoption Rates

	Low Scenario			Mid Scenario			Max Scenario		
Target Rate	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**
Bill Certainty + PTR	-	-	-	8%	20%	13%	10%	25%	16%

For small C&I customer adoption levels were also based on Brattle's Time-Varying Prince Enrollment Rates, with a reduction factor to account for the low elasticity of the small C&I sector. The team modeled three scenarios, with adoption levels ranging from 10% to 20% over the study period ending 2041. For the medium and large C&I PTR rate, the model determined the expected maximum program participation based on the incentive offered, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves developed by the Lawrence Berkeley National Laboratory[27]. The propensity curve was calibrated to the existing participation level from DRA and PowerShare. Table 7 details the adoption rate for Small C&I Bill Certainty + PTR as well as the incentive level used in the model to determine Medium & Large C&I participation.

Table 7. Adoption for C&I Rates

C&I	Low Scenario	Mid Scenario	Max Scenario
Bill Certainty + PTR (Small C&I) Adoption	10%	15%	20%
PTR (Medium & Large C&I) Incentives	$30/kW/year	$60/kW/year	$90/kW/year

2.3.9 Marketing Plan

Since PTR will be a voluntary or opt-in rate, marketing and customer education is crucial to achieving program enrollment targets. Prior to territory wide rollout, Duke should conduct additional market research to assess whether customers understand the proposed rate, gauge interest, and better

[27] Lawrence Berkeley National Laboratory, *2025 California Demand Study Potential Study: Phase 2 - Appendix F*, March 2017. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

understand barriers to adoption to develop the best methods for enrollment. This could be done through focus groups or customer surveys.

To achieve relatively high opt-in rates, Duke will provide customer marketing, education, and outreach to support implementation. Duke should engage customers by providing:

- A Menu of multiple but distinct rate options including TOU, TOU+CPP, Flat Volumetric+TOU and Bill-certainty+PTR.
- Clear, easy-to-understand messaging about available rate options
- Online tools and calculators to help customers choose the optimal rate for their lifestyle
- Technical support from staff specifically trained to resolve questions about the new rates

Duke should also expand behavioral, education, and outreach to include measurement of load reduced/shifted away from peak so that the impacts of peak reducing rates are recognizable and can be attributed the real benefits they provide to customers.

2.3.10 Measurement & Verification Plan

Evaluation of the PTR will be key to adjusting and perfecting the rate over time. Evaluation efforts should include:

- Tracking retention and attrition levels over time
- Establishing a control group that is comparable to the customers enrolled in PTR
- Evaluating load impacts and estimating enrolled customers' electricity use patterns throughout the day and over time
- Assessing different customer segments' responsiveness to calling critical event days
- Continually soliciting customer feedback on rates and marketing through customer surveys

The findings from these evaluation activities will enable Duke to refine outreach and delivery mechanisms as well as inform future rate adjustments to achieve the desired customer peak load reductions during critical events.

2.3.11 Energy Impacts and Winter Peak Demand Savings

The Tierra team's modeling results, detailed in the Winter Peak Demand Reduction Potential Assessment, found that the PTR rate options could deliver between 9.3 and 18.2 MW of peak reduction by winter 2023 and between 149.9 and 407.9 MW by 2041. PTR rate options accounted for 43% of the overall DSM rates savings, of which the Bill-certainty + PTR option accounted for 236 MW or 25% of the overall DSM rates savings. Based on these results, PTR is an important component of achieving Duke Carolina's winter demand reduction potentials in both the residential and commercial sector. It is also important to note that the modeling results of the Mid and Max scenarios found that an increase in adoption among small C&I customers and an increase in PTR incentives for the medium and large C&I customers resulted in limited additional uptake.

3. Winter Peak Targeted Program Designs

This section of the Winter Peak Targeted DSM Plan provides recommended program design concepts for each of the new Duke winter peak focused program opportunities identified in this study. These program designs include foundational information for each proposed program including the recommended program concept, target market, objectives, incentives and services, marketing and outreach, and delivery strategy.

This information is intended to assist Duke staff's development of more detailed program designs for preparation of future program filings and implementation plans. Because these are not the final program designs and the project team needed to complete a broad scope of work within a compressed schedule and limited budget, we relied on existing data sources and professional judgement to develop the estimates of measure energy savings and costs as well as first year program budgets provided in each of the following program designs. These values should be viewed as starting point estimates around which values can be refined as Duke further vets the solutions and assesses what to operationalize and when. In preparation for future program filings and implementation plans, a rigorous bottom-up measure characterization and budget analysis should be conducted based on the finalized winter peak program designs to fully assess cost-effectiveness and grid benefits. The winter peak targeted program designs include:

- Residential and Small-Medium Business Bring-Your-Own-Smart Thermostat DR Winter Peak Capacity Program ('BYOT')
- Residential and Small/Medium Business Rate-Enabled Smart Thermostat Load Shifting/DR Program ('RET')
- Residential and Small-to-Medium Business Bring-Your-Own-Battery Capacity Pilot Program ('BYO Battery')
- HVAC Comprehensive Winter Heating Efficiency Program ('Winter HVAC')
- Connected Water Heater Controls Program ('Connected WH')
- EV Workplace / Fleet Charge Management Program ('EV Manage')
- Automated Demand Response ('ADR')

3.1 Residential and Small-Medium Business Bring-Your-Own-Smart Thermostat DR Winter Peak Capacity Program ('BYOT')

Table 8. BYOT Program At-a-Glance

<table>
<tr><td>Description</td><td>– Residential and Small-to-Medium Business 'Bring Your Own' Smart Thermostat Winter Peak Demand Response Program (BYOT).
– Designed to reduce peak demand of residential and small-medium business space conditioning systems during Duke's winter peak periods as well as other peak events throughout the year.
– Deploys new and existing connected smart thermostats to respond to utility demand response (DR) events.
o Before DR events – pre-condition for up to 3 hours
o During DR events – set-back by up to 3-4 degrees F</td></tr>
<tr><td>Objectives</td><td>– Support Duke's clean energy commitments by creating scaled flexible capacity from connected smart thermostats to be dispatched during seasonal critical peak/demand response events.
– Engage customers with smart thermostats that control electric space heating systems to deliver winter peak demand reduction. Include pre-conditioning of spaces before peak demand events whenever possible to maximize program impacts and reduce the potential for customer discomfort.
– Drive greater energy affordability by providing incentives to customers in return for their participation in DR peak reduction events.
– Leverage the existing residential summer smart thermostat DR program to drive greater total benefits.</td></tr>
<tr><td>Measure Life</td><td>– Four-year effective useful life (EUL), based on a conservative assumption of how long the average participant will remain in the BYOT program.</td></tr>
<tr><td>Program Intersection with Winter Peak Needs and IRP Filings</td><td>– DR is a good tool to address winter peak issues since there are a relatively small number of total winter peak hours that drive the need for expensive winter peak capacity purchases.
– The BYOT program will leverage Duke's existing residential smart thermostat DR platform and expand it to include a focus on the winter peak season with some control hours outside of winter season as well.
– Because this program will leverage an existing program, it can be started relatively quickly with potential DR impacts provided during the 2021 winter season. There is also an opportunity to expand the program to reach the small business segment in the future.
– Smart thermostats are a low-cost measure that provide quick paybacks for participating customers.</td></tr>
<tr><td>Customer Eligibility / Targets</td><td>– Residential and small business customers in the Duke Carolinas service territory who have smart thermostats that control electric space heating.
o Participating smart thermostats must be compatible with Duke's DER aggregation platform, must connect to that platform, and must agree to allow units to be controlled to reduce demand during peak hours.</td></tr>
<tr><td>Incentive Design</td><td>– One-time incentive of $90 for customers who sign up before December 31, 2020 and $75 thereafter.
– Annual incentive of $25 for each subsequent year they participate in the program.</td></tr>
<tr><td>Required Changes to Tariffs or Rates</td><td>– This program does not require any changes to existing Duke tariffs or rates. It does not require customers to enroll in any specific rate to participate in this program.</td></tr>
<tr><td>Market Potential and Participation Goals</td><td>– The table below shows forecasted market potential goals based on the Demand Reduction Potential Assessment study.
<table>
<tr><th rowspan="2">BYOT</th><th colspan="2">2021</th><th colspan="2">2030</th></tr>
<tr><th>Units</th><th>MW Reduction</th><th>Units</th><th>MW Reduction</th></tr>
<tr><td>RES TOTAL</td><td>10,069</td><td>18</td><td>114,675</td><td>206</td></tr>
<tr><td>SMB TOTAL</td><td>450</td><td>1</td><td>4,005</td><td>9</td></tr>
<tr><td>TOTAL</td><td>10,519</td><td>19</td><td>118,680</td><td>215</td></tr>
</table></td></tr>
<tr><td>Marketing Plan</td><td>– Focus on smart thermostat in-app promotions with participating thermostat manufacturers who can promote the program directly to their smart thermostat owners in Duke's territory.
– Develop a BYOT program landing page on Duke's website and linked to thermostat manufacturer sites.
– Integrate the program into existing Duke program delivery and communication channels, including the Duke Online Marketplace for special promotions. Add capability to pre-enroll thermostats purchased on the marketplace into Duke's demand response program.
– Promote the program on social media.</td></tr>
<tr><td>Energy Impacts and Winter Peak Demand Savings</td><td>– Estimate that 10,069 residential participants and 450 SMB participants in winter BYOT program will deliver 19 MW of total peak reduction by winter 2022.
– At the end of a 10-year implementation period we expect a total incremental 2-3-hour peak load shed capacity of approximately 215 MW from this program.</td></tr>
<tr><td>Budget</td><td>– Approximately $1,677,000 to support 10,519 participants in year one, with increasing annual budgets in later years due to higher annual participation incentives needed to achieve higher capacity</td></tr>
</table>

3.1.1 Description

This program is a Residential and Small Business smart thermostat demand response program that focuses on the winter peak season. It is designed to reduce peak energy demand of residential and small-medium business space conditioning systems during Duke's winter peak periods as well as other peak events throughout the year using new and existing connected smart thermostats that will respond to scheduled demand response (DR) events. The program will leverage the EnergyHub DER aggregation platform that Duke is currently deploying for summer peak residential smart thermostat demand response.

As indicated in Duke's recent winter peak focused smart thermostat demand response program filing, the new winter peak focused DR program would offer incentives to customers who allow their thermostats to be managed for up to 45 hours during the winter season and up to 15 hours of peak demand events outside of the winter season. Duke's program filing is intended for Residential customers only at this time, but there is an opportunity to add small business customers into the program in the future – targeting small offices that typically use the same HVAC equipment and controls as residential customers. As BYOT evolves into the small and medium business market, Duke should explore expanding into additional connected load management efforts with other connected devices. This would also bolster the need for greater segmentation and C&I end use consumption data as described in the recommendations section of this report.

During a demand response event, Duke's DER aggregation platform will signal connected smart thermostats to reduce Duke's system peak during peak hours. During scheduled events, DR signals will direct connected thermostats to setback temperature settings by up to 3-4 degrees to reduce runtime during peak periods. In addition to the thermostat setback period, pre-conditioning for a period of up to 3 hours prior to the setback period is also a recommended strategy that can enhance program impacts while also improving participant comfort.

3.1.2 Objectives

The program objectives include:

- Support Duke's clean energy commitments by creating scaled flexible capacity that connects smart thermostats to Duke's DER aggregation platform to be dispatched during demand response events.
- Drive greater energy affordability by providing incentives to customers in return for their participation in DR peak reduction events.
- Target residential and small business customers with smart thermostats that control electric heat pumps or electric resistance space heating systems to deliver winter peak demand reduction benefits.
- Include pre-conditioning of spaces before peak demand events whenever possible to maximize program impacts and reduce the potential for customer discomfort.
- This approach:
    - Targets seasonal peak demand reduction during critical peak hours
    - Expands the use of an existing DER aggregation platform
    - Leverages an existing residential summer program to engage residential and small business customers to reduce both summer and winter peak
    - Targets the use of scalable DER technology that customers are rapidly adopting
    - Accelerates the opportunity to access emerging distributed energy resources

3.1.3 Measure Life

According to the Arkansas Technical Reference Manual, a smart thermostat has an expected measure life of 11 years.[28] For program potential modeling purposes, we conservatively assumed that an individual smart thermostat would stay enrolled in the Duke demand response program for an average span of four years. However, the average length of enrollment will vary based on the type of occupant (owner vs renter) and the program should encourage customers to stay enrolled in the program long-term and target customer segments that are less likely to drop out of the program.

3.1.4 Program Intersection with Winter Peak Needs and IRP Filings

The proposed program targets include both residential and small/medium business customers that collectively represent about 68% of typical system winter peak demand in the Duke Carolinas service territory. Electric space heating can account for up to 70% or more of morning winter peak demand for these customers, and smart thermostats can be used to shift that peak demand to off-peak hours. In addition, smart thermostats are being installed by Duke's residential and SMB customers today, and with the right program design strategy Duke can take advantage of this emerging consumer technology to provide added load shifting benefits.

Demand response is a good tool to address winter peak issues for Duke Carolinas since there are a relatively small number of total winter peak hours that drive the need for expensive winter peak capacity purchases. Due to the nature of Duke's short duration winter morning peaks, the winter peak study modeling results indicate that demand response and load shifting are very effective strategies that can reduce peak energy needs without creating additional peak challenges that could be caused by potential snapback effects. Duke can also deploy advanced load shaping such as end time randomization of DR setbacks to minimize snapback effects if they become a concern in the future.

Smart thermostat programs have been successfully implemented by Duke and other utilities for summer peak reduction but less utilized to date for winter peak programs. This program will leverage Duke's existing DER aggregation program for summer DR with residential smart thermostats and expand it to include a focus on the winter peak season with some limited hours of control outside of winter season as well. Because this program will leverage an existing program, it can be started relatively quickly with potential DR impacts provided during the 2020-2021 winter season. There is also an opportunity to expand the program to reach the small business segment in the future.

3.1.5 Customer Eligibility/Targets

This program will target residential and small business customers in the Duke Carolinas service territory who have purchased and installed smart thermostats to control electric space heating. All eligible smart thermostats must be compatible with Duke's smart thermostat DER aggregation platform.

The residential market provides the most opportunity for peak reduction through the BYOT program. We project that 114,675 residential smart thermostats will be installed by 2030.

Duke Carolinas customers who own or are adopting smart thermostats will be primary targets for this program, but only if their installed smart thermostats control electric heat pumps or resistance heating systems. This is an important distinction, and Duke should consider approaches for targeting customers

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[28] Arkansas Public Service Commission, *Arkansas TRM Version 8.1 Vol. 1*, August 31.

with eligible central electric heating systems as well as developing program processes to ensure that thermostats control central electric heating systems before they receive a rebate.

Program participants can be served under any current existing Duke rate or tariff, and the program does not require a specific rate as a prerequisite to participate. However, in the modeling of the winter peak solution set, it was assumed that customers who participate in the proposed Peak Time Rebate (PTR) program would not be eligible to participate in this program. In addition, it was assumed that customers who elect to participate in the proposed Rate Enabled Smart Thermostat Program would also be eligible to participate in the smart thermostat demand response program.

As indicated in the recent Duke winter peak focused smart thermostat DR program filing, participating customers must be willing to allow direct response signals to adjust their smart thermostat temperature settings for up to 45 hours each winter peak control season and for up to 15 hours outside of the winter season. Program participants are required to keep their thermostat connected and online so that it can be dispatched for events throughout the duration of the program.

3.1.6 Customer Bill Savings & Benefits

Customers who install smart thermostats receive energy efficiency savings from the ongoing efficient operation of the thermostat. According to the Arkansas Technical Reference Manual, on average, customers with properly programmed smart thermostats will save 0.113 kWh/SF in electric cooling energy, 0.212 kWh/SF in electric resistance heating energy, and 0.099 kWh/SF in electric heat pump heating energy each year.[29] In addition, customers also benefit from annual participation incentives each year they participate in the smart thermostat demand response program.

As proposed in the recent Duke winter peak focused smart thermostat demand response filing, participants will benefit from a one-time incentive of $90 when they sign up before December 31, 2020 and $75 thereafter. Participants will also receive an annual incentive of $25 for each subsequent year they participate in the winter peak focused demand response program.

In general, participants will not see a significant impact on their energy costs from this program other than the participation incentives they receive. Customers on time differentiated rates could see potential savings from the program due to shifting energy off-peak, but potential annual energy impacts are minimal because the program only applies for a maximum of 60 hours per year.

3.1.7 Incentive Design

As proposed in the recent Duke winter peak focused smart thermostat demand response filing, participants will receive a one-time incentive of $90 when they sign up before December 31, 2020 and $75 thereafter. Participants will also receive an annual incentive of $25 for each subsequent year they participate in the winter peak focused demand response program.

Duke should also pursue a program design that allows customers who purchase DR eligible smart thermostats on Duke's online marketplace to receive an instant upfront incentive and be automatically pre-enrolled in the winter focused DR program. This is a current best practice that can significantly increase the number of thermostats that become enrolled in the smart thermostat DR program.

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[29] Arkansas Public Service Commission, Arkansas TRM Version 8.1 Vol. 2: Deemed Savings, Table 70, page 85, August 31, 2019. http://www.apscservices.info/EEInfo/TRMV8.1.pdf

3.1.8 Required Changes to Tariffs or Rates

This program does not require any changes to existing Duke tariffs or rates. It does not require customers to enroll in any specific rate to participate in this program. It is focused on reducing residential winter kW demand during peak demand periods, so it could provide additional cost savings benefits for customers who choose Time of Use rates and other innovative, time-differentiated rate designs and tariffs.

Although not necessary for launching the BYOT program, the introduction of a fixed-bill subscription plan as described previously in section 2.3 would benefit BYOT by expanding the opportunity for customer classes such as low-moderate income customers and small businesses, which typically are less likely to participate in demand response programs due to non-performance risk, to participate. The DER aggregation platform, smart device installation procedures, and other infrastructure developed in the BYOT program can also be leveraged by the fixed-bill subscription plan, reducing costs and easing the deployment process. In addition to using smart thermostat data from the BYOT program to target homes that are the best candidates for the subscription plan.

3.1.9 Implementation and Operation

Demand Response Control Parameters

Duke will use its smart thermostat DER platform to aggregate multiple smart thermostat brands under one demand response program that operates year-round, with a focus on winter season.

As indicated in the recent Duke winter peak focused smart thermostat DR program filing, participating customers will agree to allow direct response signals to adjust their smart thermostat temperature settings for up to 45 hours each winter peak control season and for up to 15 hours per year outside of the winter season.

Considerations

Whenever possible, smart thermostat DR events should be conducted with pre-conditioning prior to the peak event period in addition to temperature setbacks during the peak. While pre-conditioning is not required for the program to reduce Duke's winter or summer kW peak, it is strongly recommended, since pre-conditioning can deliver the following benefits:

- Increases peak demand impacts for the program during the critical peak period
- Minimizes "snapback" post event kW demand spikes that can create adverse load shape impacts
- Reduces customer overrides and opt outs due to negative impacts on comfort
- Helps improve customer retention in DR programs due to minimized comfort impacts
- Delivers low-cost thermal storage for customers and Duke

3.1.10 Market Potential and Participation Goals

Residential

The most recent residential appliance saturation survey (RASS) for the Duke Carolinas service territory estimates that 15% of all installed residential thermostats are smart thermostats. Manufacturers estimate that there are 435,000 smart thermostats installed in this territory. Note that some homes may have more than one smart thermostat installed.

There are currently about 20,000 smart thermostats enrolled in Duke's summer BYOT program.

Note that participating smart thermostats must control electric central space heating systems to qualify for the winter peak focused DR program, meaning that not all these thermostats would be eligible to participate in the winter peak DR program. Residential and small business customers with smart thermostats that are not compatible with Duke's thermostat aggregation platform and units that do not control electric space heating systems are not eligible to participate in the smart thermostat demand response program.

Duke currently does not have saturation survey data available to estimate the percentage of all-electric residential customers with supplemental heat strips. We were, however, able to estimate the total heat load for homes with electric heating for both DEC and DEP. These estimates represent the average of 6 winter peak events in 2018; as such we expect that the single annual system winter peak day would be slightly higher, but we expect that the distribution of electric heating load between heat pump condensers and other electric resistance heating remains constant.

- **For DEC** we estimate the total electric space heating load is 2,500 MW based on analysis of average winter peak events in 2018, and that this total demand is comprised of 1,500 MW (60%) from heat pump condensers and 1,000 MW (40%) from electric resistance heating, which includes supplemental heat strips on heat pumps, electric wall furnaces, electric baseboard heaters, and small supplemental plug-in heaters. While we were unable to isolate the exact contribution from supplemental heat strips on heat pumps, we do consider it to be significant, representing from one-to-two thirds of the residential electric resistance space heating load, or 300 to 600 MW.
- **For DEP** we estimate the total electric space heating load is about 1,500 MW for the average winter peak day, including 900 MW from heat pump condensers and 600 MW from electric resistance heating. Like DEC, we estimate that supplemental heat strips on heat pumps account for 180 to 360 MW of resistance heating load with electric wall furnaces, electric baseboard heaters, small supplemental plug-in heaters accounting for the balance.

Small-and-Medium Commercial

In aggregate, the SMB segment has a typical commercial building demand profile where load begins ramping early and peaks between 7:00 a.m. and 9:00 a.m.

According to study results, the SMB winter morning peak demand typically reaches about 40% of the size of the residential winter morning peak. While there is a much larger diversity of end uses within the small and medium commercial segment when compared to the residential market, research indicates that the morning winter peak demand in this segment is driven primarily by electric space heating.

Across all Duke Carolinas small and medium C&I customers, we estimate the morning heating load to be approximately 830 MW, and this commercial load profile is not being addressed in the current set of Duke's DSM programs. There is currently no small and medium business segment end-use saturation survey that is comparable to the RASS, but industry subject matter experts estimate the number of smart thermostats installed across the SMB customer base is approximately 10% of the residential saturation, or about 43,500 units in total.

Most Duke Carolinas' SMB customers are currently served under rates that do not have a time differentiated component.

3.1.11 Marketing Plan

An integrated marketing plan should be developed to target both Residential and, in the future, Small Business customers who are eligible and most likely to participate in the program including:

- Run in-app promotions with participating thermostat manufacturers who can promote the program direct to smart thermostats in Duke's territory

- Create program landing pages on Duke's website and linked to thermostat manufacturers
- Integrate this program into existing program delivery channels for other existing residential programs including HVAC and home performance
- Scale the program in conjunction with the introduction of new innovative rates and tariffs that can pair well with smart thermostat technology
- Use landing pages and banners on the Duke Online Marketplace for special promotions to drive traffic to purchase qualifying smart thermostats that are automatically pre-enrolled in the DR program
- Utilize Duke's in-house customer information channels (e.g., emails, newsletters, bill inserts)
- Promote the program on social media

3.1.12 Measurement and Verification Plan

A detailed Measurement & Verification (M&V) Plan should be developed for this program, which will require coordination between Duke Energy and Duke's evaluation contractor. The M&V plan should be designed to ensure that the program meets utility, customer, and regulatory objectives and key performance indicators.

Important M&V areas of focus for this program will include:

- Process evaluation to determine opportunities to streamline and improve program processes and improve customer experience/participant satisfaction, including metrics such as:
    - Frequency of event opt outs and overrides
    - Post enrollment, post event and post season surveys
- Impact evaluation to determine the program's energy impacts including:
    - Description of baseline methodology
    - Measuring hourly peak kW demand impacts from dispatched DR events
    - Complete analysis of load shape impacts compared to baseline before, during and after DR events
    - Impacts per thermostat disaggregated by various criteria including dwelling type, control type, etc.
    - Developing better forecasting of program impacts based on specific weather conditions and DR event parameters

3.1.13 Energy Impacts and Winter Peak Demand Savings

Duke should first target existing residential summer DR program participants and then pursue new residential and SMB participants.

During DR event days the Tierra team estimates that this program will deliver winter peak reduction impacts of up to 1.25 kW for MF, 2.03 kW for single-family, and up to 2.22 kW for SMB customers per enrolled thermostat. This is an aggregated averaged that accounts for all event opt-outs, overrides, and offline devices. These impacts are weather dependent, particularly due to the potential kW impacts of electric resistance heat strips, and we expect lower impacts if deployed on non-peak winter days, while impacts may be higher than these estimates during the coldest weather events.

We anticipate that 10,069 residential participants and 450 SMB participants in the winter BYOT program could deliver up to 19 MW of total peak reduction by winter 2022. At the end of a 10-year implementation period we expect a total incremental peak load shed capacity of approximately 215 MW from this program.

3.1.14 Budget

The following estimated first year program budget is based on the preliminary program design concept as discussed above and the Tierra team's years of experience in program design and implementation. It assumes:

- 10,069 residential customers and 450 commercial customers in year 1
- Incentives of:
  - $75/Enrollment Incentive ($90/Enrollment offered in year 1 only)
  - $25/Seasonal reward[30]

Estimated first year program rebate and incentive costs are presented in Table 9 below.

Table 9. BYOT Program Estimated First Year Rebate and Incentive Costs (Winter Only)

Rebate/Incentive	Quantity	Value per Unit	Total Cost (Year 1)
Res Enrollment Incentive	10,069	$90	$906,210
Com Enrollment Incentive	450	$90	$40,500
Total			**$946,710**

Estimated first year program costs, including rebates/incentives and program administration, are presented in Table 10 below. Note that annual costs for this program are expected to increase as more capacity is added to the program.

Table 10. BYOT Program Estimated First Year Budget

Budget Category	Percentage	Year 1 Cost
Rebates and Incentives	48%	$946,710
Program Implementation	38%	$750,000
Program Marketing and Outreach	8%	$150,000
Planning and Administration	7%	$ 160,000
Total	**100%**	**$ 1,981,7100**

[30] Note that seasonal incentive costs of $25/season are only applicable in years after enrollment.

3.2 Residential and Small/Medium Business Rate-Enabled Smart Thermostat Load Shifting/DR Program ('RET')

Table 11. RET Program At-a-Glance

<table>
<tr><td>Description</td><td>– Designed to reduce on-peak energy use of residential single and multifamily and small-to-medium business space conditioning year-round using smart thermostats that are pre-programmed to work in coordination with Duke's time differentiated rate plans.
– Focuses on newly installed smart thermostats, but it could also be applied to existing smart thermostats that can receive remote updates to add rate optimization capabilities.
– In the recommended program design, participants receive a free rate enabled smart thermostat as an incentive to participate in the program and enroll in a time differentiated rate plan.</td></tr>
<tr><td>Objectives</td><td>– Provide bill savings for customers by installing smart thermostats that are pre-programmed with Duke TOU/innovative rates to shift HVAC use around Duke's on-peak periods to reduce on-peak energy use.
– Engage customers to install free smart thermostats that control electric space conditioning systems to provide energy efficiency, load shifting and demand response savings and benefits.
– Offer automated load shifting that makes it easy and convenient for customers to save on Duke's time differentiated rate plans while also using pre-conditioning to reduce customer discomfort.
– Create additional flexible capacity by connecting RET units to Duke's DER aggregation platform to be dispatched during critical peak/demand response events.
– Leverage DER technology that customers want and install it for free so that any customer can afford to participate and receive access to bill saving benefits.
– Offer customers more advanced smart thermostats than they might otherwise purchase on their own.</td></tr>
<tr><td>Measure Life</td><td>– 10-year effective useful life (EUL).</td></tr>
<tr><td>Program Intersection with Winter Peak Needs and IRP Filings</td><td>– Addresses residential and commercial heating loads that drive Duke's winter peak needs.
○ Residential customers represent 53% of total system winter peak demand, and electric space heating accounts for 70% of morning winter peak for a typical all electric households from 6:00 to 9:00 a.m.
○ SMB customers represent about 15% of total system winter peak demand; HVAC and lighting loads account for most of their winter peak demand from 7:00 a.m. to 9:00 a.m.
– Rate-enabled smart thermostats allow participants to automatically save money on time differentiated rates while helping Duke reduce winter peak demand.
– Load shifting and demand response are effective approaches for addressing Duke's winter peak issues since there are a relatively small number of total winter peak hours that drive winter capacity needs.</td></tr>
<tr><td>Customer Eligibility / Targets</td><td>– To be eligible, customers must enroll in one of Duke's compatible res/com time differentiated rate plans and agree to participate in demand response for at least one year.
– The program should target:
○ Residential and small business customers in the Duke Carolinas service territory to encourage installation of rate enabled smart thermostats that control electric space heating.
○ Local MF property owners to complete a direct installation for all dwelling units and enroll large numbers of MF residential customers, including limited income properties.</td></tr>
<tr><td>Incentive Design</td><td>– The exact incentives will depend on the specific thermostat technologies and delivery strategies that Duke selects. To complete our analysis, we assumed a total cost of up to $250 per installed thermostat, which assumes $125 toward the purchase price of the RET and $125 towards installation. This assumption was based upon experience in other utility territories. We recommend that these cost assumptions be updated and vetted when a final program design is developed.</td></tr>
<tr><td>Required Changes to Tariffs or Rates</td><td>– This program does not require any changes to existing Duke tariffs or rates. The program design could be modified to work with many different potential Duke time differentiated rate designs.
– Program participants will be required to enroll in a qualifying time differentiated rate plan.</td></tr>
<tr><td>Market Potential and Participation Goals</td><td>– The table below shows forecasted market potential goals based on the Demand Reduction Potential Assessment study.
<table>
<tr><th rowspan="2">RET</th><th colspan="2">2022</th><th colspan="2">2030</th></tr>
<tr><th>Units</th><th>MW Reduction</th><th>Units</th><th>MW Reduction</th></tr>
<tr><td>RES TOTAL</td><td>3,000</td><td>6</td><td>24,407</td><td>40</td></tr>
<tr><td>SMB TOTAL</td><td>450</td><td>1</td><td>2,274</td><td>5</td></tr>
<tr><td>TOTAL</td><td>3,450</td><td>7</td><td>26,681</td><td>45</td></tr>
</table></td></tr>
<tr><td>Marketing Plan</td><td>– Integrate this measure into existing program delivery channels for MF and LMI programs
– Work with EnergyHub to ensure integration with other DER programs
– Conduct outreach with MF property managers
– Market the program in conjunction with introduction of new innovative rates and tariffs</td></tr>
<tr><td>Energy Impacts and Winter Peak Demand Savings</td><td>– We anticipate that 3,000 residential participants (2,400 SF + 600 MF) and 450 SMB participants will deliver 7 MW of total peak reduction by the winter of 2023.
– At the end of a 10-year implementation period we expect a total incremental peak load shed capacity of approximately 45 MW from this program.</td></tr>
<tr><td>Budget</td><td>– $1,838,000 in year one, with increasing annual budgets in later years due to higher annual participation incentives needed to achieve higher capacity.</td></tr>
</table>

3.2.1 Description

This program is designed to reduce on-peak energy use of residential single/multifamily and commercial small/medium business space conditioning during Duke's peak periods year-round using smart thermostats that are pre-programmed to work in coordination with Duke's time differentiated rate plans. The proposed program design focuses on newly installed smart thermostats, but it could also be applied to existing smart thermostats that can receive remote updates to add rate optimization capabilities.

Participants receive a free rate enabled smart thermostat as an incentive to sign up for the program and enroll in one of the required time differentiated rate plans (example eligible rate plans could include existing rates such as R-TOU-62, R-TOUD-62, and RT TOU (SC) for residential customers and SGS-TOU-62, SGS-TOUE-62 for SMB customers, as well as new innovative rate designs if they can be supported by smart thermostat algorithms). Depending on the rate design being deployed, participants could also be required to enroll in the residential smart thermostat winter peak demand response program for one year as part of the requirements for receiving a free smart thermostat.

The rate enabled thermostats will be pre-programmed to support year-round peak reduction by pre-conditioning prior to peak periods and then setting back thermostats during the peak to reduce runtime, ideally with customers having the ability to adjust the range of adjustment according to their comfort preferences and energy savings goals. During critical peak DR events these thermostats could also react to demand response signals through Duke's DER aggregation platform. Participants always retain control of their thermostat settings and can override or adjust their thermostats at any time during events.

Winter Peak Periods

Table 12. Example Winter Peak Periods of Current Duke Rates

TOU RATES - DUKE (Pilots not included)	Utility/ Class	Winter On-Peak + Shoulder Hours			
		M-F On-Peak - excl Holidays (start)	M-F On-Peak - excl Holidays (stop)	M-F Shoulder - excl holidays (start)	M-F Shoulder - excl holidays (stop)
SMALL GENERAL SERVICE (TIME-OF-USE) SCHEDULE SGS-TOU-62	DEP/ SGS	6:00 AM 4:00 PM	1:00 PM 9:00 PM		
SMALL GENERAL SERVICE ALL-ENERGY TIME-OF-USE SCHEDULE SGS-TOUE-62	DEP/ SGS	6:00 AM	9:00 AM	9:00 AM 5:00 PM	Noon 8:00 PM
RESIDENTIAL SERVICE TIME-OF-USE SCHEDULE R-TOU-62	DEP/ RES	6:00 AM	9:00 AM	9:00 AM 5:00 PM	Noon 8:00 PM
RESIDENTIAL SERVICE TIME-OF-USE SCHEDULE R-TOUD-62	DEP/ RES	6:00 AM 4:00 PM	1:00 PM 9:00 PM		
SCHEDULE RT (SC) RESIDENTIAL SERVICE, TIME-OF-USE	DEC/ RES	7:00 AM	Noon		

Winter Operation

The exact operation of thermostats for this program will be determined by Duke in conjunction with the specific smart thermostat technologies and products being deployed. In general, thermostat optimization protocols should create a softer touch for daily load shifting events around Duke's peak rate periods, with increased load shifting occurring for specific critical peak periods and/or DR event periods. If possible, the thermostat user experience should allow customers to set and adjust their preferences for daily load shifting parameters to create custom settings based on their comfort and energy savings priorities.

To model the potential program impacts, the study assumed that on average during the winter these rate-enabled thermostats will be programmed to react to Duke's winter peak rate periods, as follows:

- Pre-heat by 2 degrees F for up to three hours before peak periods
- Setback residences and SMBs by 2 degrees F during peak periods
- Return to the temperature set by the occupants after peak periods

During winter demand response (DR) events from October through March, these adjustments could increase to 3 or 4 degrees for the pre-heat period and 3- or 4-degree setback temperature settings during the peak.

Summer Peak Periods

Table 13. Example Summer Peak Periods of Current Duke Rates

TOU RATES - DUKE (Pilots not included)	Utility/ Class	Summer On-Peak + Shoulder Hours			
		M-F On-Peak - excl Holidays (start)	M-F On-Peak - excl Holidays (stop)	M-F Shoulder - excl holidays (start)	M-F Shoulder - excl holidays (stop)
SMALL GENERAL SERVICE (TIME-OF-USE) SCHEDULE SGS-TOU-62	DEP/ SGS	10:00 AM	10:00 PM		
SMALL GENERAL SERVICE ALL-ENERGY TIME-OF-USE SCHEDULE SGS-TOUE-62	DEP/ SGS	1:00 PM	6:00 PM	11:00 AM 6:00 PM	1:00 PM 8:00 PM
RESIDENTIAL SERVICE TIME-OF-USE SCHEDULE R-TOU-62	DEP/ RES	1:00 PM	6:00 PM	11:00 AM 6:00 PM	1:00 PM 8:00 PM
RESIDENTIAL SERVICE TIME-OF-USE SCHEDULE R-TOUD-62	DEP/ RES	10:00 AM	9:00 PM		
SCHEDULE RT (SC) RESIDENTIAL SERVICE, TIME-OF-USE	DEC/ RES	1:00 PM	7:00 PM		

Summer Operation

We've assumed the same scenario for summer operation, although specific protocols will vary depending on the specific rate designs and technologies/products being deployed. On average, during the summer these rate-enabled thermostats can be programmed to react to Duke's summer peak periods, as follows:

- Pre-cool by 2 degrees F for up to three hours before peak periods

- Setback by 2 degrees F during peak periods
- Return to the temperature set by the occupants after peak periods

During summer demand response events these thermostats can increase to 3-4-degree pre-cool and 3-4-degree setback temperature settings.

Access to Rate Enabled Thermostats

Rate enabled smart thermostats will be provided free to customers who sign up for eligible Duke residential or SMB TOU or innovative rate plans and who also commit to participate in Duke's smart thermostat demand response program for one year.

Rate enabled thermostats can be made available through multiple Duke programs and delivery channels for existing homes, multifamily, and limited income residences as well as small/medium businesses including the existing Smart $avers program and the Duke's Online Marketplace, the "Online Savings Store".[31]

Note that there are a few RET manufacturers in the market today, but the technology is still very nascent. There are a limited number of viable options available, and many are early-generation models that don't necessarily work as well as OEMs - or utilities - would like. We expect that this will change soon, and that more models will become available.

There are also several issues that Duke must work through with the OEMs as an industry. For example, thermostat manufacturers have concerns about giving aggregators and utilities control over the RET units for daily optimization. That said, RETs are compelling technology and can deliver an array of benefits (load shifting, peak reduction, rate savings) to customers and utilities alike. Duke should continue to work with thermostat manufacturers in a consortium with other utilities to realize these benefits for all customers.

3.2.2 Objectives

The primary goals of the RET program are to:

- Provide bill savings for customers by offering smart thermostats that are pre-programmed to respond to TOU/innovative rates to shift HVAC usage around Duke's on-peak periods to save energy costs.
- Offer automated load shifting that makes it easy and convenient for customers to save on Duke's time differentiated rate plans while also using pre-conditioning to reduce potential customer discomfort.
- Create added flexible capacity by connecting these thermostats to Duke's DER aggregation platform to be dispatched during critical peak/demand response events.
- Engage residential and small-medium business customers who are interested in receiving a free smart thermostat to control their electric heat pump or electric resistance space heating systems to provide energy efficiency, load shifting and demand response savings and benefits.
- This approach:
    - Targets year-round peak demand reduction as well as critical peak hours

[31] At Online Savings Store - Duke Energy (duke-energy.com)

- Leverages a DER technology that customers want and offers it for free so that any customer can afford to take part (including limited income customers and renters) and receive access to bill saving benefits
- Provides customers with more advanced smart thermostats than they would otherwise be able to buy that are optimized to work in conjunction with Duke's rate structures
- This program can be particularly applicable for multifamily rental properties. Tierra is currently working with a large multi-family property owner who owns rental units in Duke Carolinas territory, and they are interested in adding smart thermostats to their rental properties in coordination with a utility program

3.2.3 Measure Life

According to the Arkansas Technical Reference Manual, a smart thermostat has an expected measure life of 11 years.[32]

3.2.4 Program Intersection with Winter Peak Needs and IRP Filings

Residential customers represent 53% of total system winter peak demand, and electric space heating accounts for about 70 percent of morning winter peak demand for the average all electric residential household between the hours of 6:00 a.m. and 9:00 a.m. Smart controls can be used to shift demand to off-peak hours, and deploying rate enabled thermostats makes it easy for participants to save money on time differentiated rates while helping Duke reduce a significant source of winter peak demand.

Small/medium business (SMB) customers represent about 15% of total system winter peak demand, and commercial building HVAC and lighting systems are primarily responsible for the SMB winter peak demand contribution between the hours of 7:00 a.m. and 9:00 a.m. Typical HVAC units in these facilities are often like residential HVAC equipment and smart thermostats can be an effective tool to save energy and shift demand to off-peak hours.

The design of the Rate Enabled Smart thermostat program is expected to deliver both winter and year-round system peak reduction while also providing participant energy efficiency and bill savings benefits at a competitive cost. This program should be especially useful to address winter peak issues for Duke Carolinas since there are a small number of total winter peak hours that drive the need for expensive winter peak capacity purchases, providing opportunities for both load shifting and demand response to offer high resource value. Smart thermostats are being installed by Duke's customers today, and many customers are interested in the technology but may not be able to afford the upfront cost. This program offers free smart thermostats that help enable customers to adopt the technology while allowing Duke to scale load shifting and peak reduction benefits.

3.2.5 Customer Eligibility / Targets

This program will target residential and small-medium business customers in the Duke Carolinas service territory who would like to install free, new, rate-enabled smart thermostats to control their electric space heating systems and work in coordination with Duke's rate plans. This initial program design excludes customers who already have smart thermostats installed, although existing thermostats could be

[32] Arkansas Public Service Commission, *Arkansas TRM Version 8.1 Vol. 1*, August 31.

accommodated in the program through software updates that could push new algorithms to rate optimize existing thermostats.

Through the offer of a free smart thermostat, the program can be targeted to reach limited income households and customers who live in multifamily dwellings who may not otherwise have access to the benefits of smart thermostat technology. By combining the smart thermostat operation with a compatible Duke rate plan, this free technology can provide participants with significant ongoing bill savings. This program design can be particularly applicable to scaling participation in multifamily dwellings by partnering with local MF property owners with direct install campaigns and/or pay for performance contracts that provide incentives for ongoing peak demand reductions.

This program requires customers to enroll in one of Duke's compatible residential or commercial time differentiated rate plans (including rates such as R-TOU-62 and R-TOUD-62 for residential customers and SGS-TOU-62, SGS-TOUE-62 for SMB customers as well as new innovative rate designs) and could also include a requirement to participate in the BYOT smart thermostat demand response program for at least one year depending on the specific rate design.

3.2.6 Customer Bill Savings & Benefits

Participants benefit from multiple streams of ongoing benefits including:

- Free state-of-the-art rate enabled and connected smart thermostat valued at $125
- Ongoing annual energy efficiency savings from the use of the smart thermostat
- Ongoing potential bill savings from enrollment in a TOU rate and use of rate optimized thermostat
- Potential annual incentive payments for continuing in the demand response program after one year

3.2.7 Incentive Design

The incentive design for this program is intended to cover the purchase (and potentially direct install) of an eligible rate enabled smart thermostat. Eligible thermostats could be delivered through the existing multifamily homes and limited income programs as a direct installation item. Thermostats could also be fulfilled through Duke's online marketplace, where customers may have to pay for installation services.

The exact incentives will depend on the specific thermostat technologies and delivery strategies that Duke selects. To complete our analysis, we assumed a total cost of up to $250 per installed thermostat, which assumes $125 toward the purchase price of the RET and $125 towards installation. This assumption was based upon experience in other utility territories. We recommend that these cost assumptions be updated and vetted when a final program design is developed.

For the marketplace online sales channel, Duke should pursue a program design that allows customers who buy rate-enabled smart thermostats through the Duke Online Marketplace to be automatically pre-enrolled in Duke's smart thermostat DR program. This is a current program best practice that can significantly increase the number of thermostats that become enrolled in the program.

Note that this incentive design is for newly bought smart thermostats. In addition to this design, Duke could pursue a strategy to deploy rate optimized software updates for customers with existing smart thermostats in conjunction with thermostat manufacturers and/or third-party implementers.

3.2.8 Required Changes to Tariffs or Rates

This program does not require any changes to existing Duke tariffs or rates, but it could be combined with future time differentiated rate designs. The program will require participants to be enrolled in a qualifying TOU or innovative rate/tariff to receive an incentive. This is to ensure that participants provide ongoing peak demand reductions from the rate enabled thermostats and benefit from ongoing bill savings when combined with these time differentiated rates.

3.2.9 Implementation and Operation

Year-Round, Rate-Enabled Control Parameters

Participating RET smart thermostats will be programmed to automatically respond to specific Duke TOU rates by pre-conditioning spaces before peak and setting temperatures back during peak hours to achieve peak demand reduction. This is intended to be a flexible program that can be applied and adjusted based on future winter and summer peak resource needs and rate plans, including TOU rates as well as critical peak pricing and fixed bill rate designs. In these programs, Duke can also enroll these thermostats in the winter peak focused BYOT smart thermostat demand response program and connect these thermostats into Duke's DER aggregation platform. Note that these thermostats will not provide as much demand response value due to their daily load shifting; however, they can provide some incremental demand response capacity. Our modeling assumptions are based on a 2-degree pre-condition and setback on load shifting days and a 3-degree pre-condition and setback during demand response events. These events can also be coordinated with critical peak pricing periods. To avoid overcompensating demand reductions, customers who participate in the BYOT smart thermostat demand response element of the program would not be eligible to participate in peak time rebates.

Considerations

The RET program should be implemented with both pre-conditioning and setback strategies to maximize impacts and customer savings while also minimizing comfort issues. While pre-conditioning is not required for the program to reduce Duke's winter or summer kW peak, it is strongly recommended that Duke promote it, since pre-conditioning can deliver the following benefits:

- Increases peak demand impacts for the program during on-peak periods
- Minimizes "snapback" post event kW demand increases that can create adverse load shape impacts
- Improves participant comfort during events and minimizes overrides and opt outs due to negative impacts on comfort
- Offers more reliable, cost-effective peak demand savings through minimization of 'customer churn'
    - Helps build greater capacity over time and reduces ongoing marketing costs through lower program attrition rates
- Provides a low-cost thermal storage opportunity for customers and Duke
- Offers customers the opportunity to maximize bill savings from energy efficiency, load shifting with time differentiated rates, and demand response incentives

3.2.10 Market Potential and Participation Goals

The most recent residential appliance saturation survey (RASS) for the Duke Carolinas service territory estimates that 15% of all installed residential thermostats are smart thermostats. While there has been rapid customer adoption of smart thermostats, there is still significant growth potential available to reach the remaining market. Manufacturers estimate that there are 435,000 smart thermostats installed in this territory. Note that some homes have more than one smart thermostat installed, with an estimated average of 1.2 thermostats/home.

There are significant opportunities for the rate enabled smart thermostat program to be successful in Low-Moderate Income (LMI), Small-to-Medium Business (SMB), and Multi-Family (MF) segments where customers are less likely to adopt this technology without assistance. The free smart thermostats in this program will encourage participation from these segments and provide ongoing bill savings through TOU rates for all participating customers. To be eligible to participate, the smart thermostat must control a central HVAC system with electric space heating that is compatible with the selected smart thermostat technology. Participating smart thermostats must also be capable of responding to Duke's time differentiated rate plans and must be compatible with Duke's DER aggregation platform.

3.2.11 Marketing Plan

An integrated marketing plan should be developed to target both the Residential and SMB sectors with the following characteristics:

- Market this program in conjunction with introduction of new innovative rates and tariffs.
- Integrate this program into existing program delivery channels for multifamily and limited income programs and conduct outreach with multi-family property managers.
- Use special landing pages and banners on the Duke Online Marketplace to drive traffic to free rate enabled thermostat promotions
- Utilize Duke's in-house customer information channels (e.g., emails, newsletters, bill inserts)
- Promote the program on social media

3.2.12 Measurement & Verification Plan

A detailed Measurement & Verification (M&V) Plan should be developed for this program in coordination between Duke Energy and Duke's evaluation contractor. The M&V plan must be designed to ensure that the program meets targeted utility, customer, and regulatory metrics.

Important M&V areas of focus for this program will include:

- Process evaluation to find opportunities to streamline and improve program processes and Customer experience/participant satisfaction, including metrics such as:
  - Frequency of opt outs, overrides and thermostat setpoint adjustments
  - Post event and post season surveys – for DR events as well as daily load shifting
- Impact evaluation to determine the program's energy impacts including:
  - Developing accurate baselines
  - Determining research design and establishing any needed control group
  - Verifying monthly/annual kWh savings from energy efficiency functionality
  - Peak kW demand impacts from rate enabled load shifting
  - Peak kW demand impacts from dispatched DR events
  - Complete analysis of load shape impacts compared to baseline before, during and after load shifting and DR events
  - Impacts per thermostat disaggregated by various criteria including rate plan, dwelling type, control type, thermostat type, and other program parameters

3.2.13 Energy Impacts and Winter Peak Demand Savings

On typical winter days when load shifting algorithms are deployed to shift energy off-peak, we estimate that the average peak hour impacts of the rate enabled smart thermostat program will be approximately 0.6 kW for multifamily dwellings, 1.1 kW for single-family, and 0.4 kW for small/medium business customers. During winter DR event days when larger pre-condition and setback settings will be used, we estimate that each rate-enabled smart thermostat enrolled in the BYOT program will deliver average total peak reduction impacts of 1.25 kW for multifamily dwellings, 2.03 kW for single-family, and 2.22 kW for small/medium business customers. We expect that these RET units will deliver the same benefit as those for the BYOT program during peak events. It is important to note, of course, that impacts will be weather dependent and based upon the extent of the use of electric resistance heat strips in heat pumps. During the coldest weather events we expect that per thermostat impacts may be higher than these estimates.

We anticipate that 3,000 residential participants (2,400 SF + 600 MF) and 450 small/medium business participants in the rate enabled thermostat program will deliver 7 MW of total peak reduction by winter 2023. At the end of a 10-year implementation period we expect a total incremental peak load shed capacity of 45 MW from this program.

3.2.14 Budget

The following estimated program budget is based on the preliminary program design concept as discussed above and the Tierra experience in program design. Our suggested 1st year program budget assumes:

- 3,000 residential and 450 commercial customers in year 1
- Incentives consisting of free rate-enabled smart thermostats, assuming:
  - $125/Unit + $125/Installation (included if this is deployed as a direct install program)

Estimated first year program rebate and incentive costs are presented in Table 14 below.

Table 14. RET Program Estimated First Year Rebate and Incentive Costs (Winter Only)

Rebate/Incentive	Quantity	Value per Unit	Total Cost (Year 1)
Res Free Rate-Enabled Smart Thermostat	3,000	$250	$750,000
Com Free Rate-Enabled Smart Thermostat	450	$250	$112,500
Total			**$862,500**

Estimated first year program costs, including rebates/incentives and program administration, are presented in Table 15 below.

Table 15. RET Program Estimated First Year Budget

Budget Category	Percentage	Year 1 Cost
Rebates and Incentives	47%	$862,500
Program Implementation	38%	$690,000
Program Marketing and Outreach	8%	$150,000
Planning and Administration	7%	$ 135,000
Total	**100%**	**$ 1,837,500**

3.3 Residential and Small-to-Medium Business Bring-Your-Own-Battery Capacity Pilot Program ('BYO Battery')

Table 16. BYO Battery Pilot Program At-a-Glance

Description	– The Bring-Your-Own Battery Capacity Pilot Program (BYO Battery) is designed to provide incentives to residential and small business customers who own or are buying energy storage systems and agree to share the capacity of their battery systems for winter peak (and potentially year-round) load shifting and/or demand response events. Potential designs for this program include: o BYO Battery Load Shifting Capacity Pilot: offer incentives for customers to enroll batteries in the program and share performance data. Require customers to be enrolled in a time differentiated rate plan and to commit to charge batteries off-peak and dispatch batteries on-peak only. Includes an upfront incentive to enroll, could also include annual participation incentive. o BYO Battery Demand Response Capacity Pilot: offer an upfront incentive plus a pay for performance incentive for customers to enroll and then allow Duke to access battery capacity through DR events. Incentives would be paid on a per kW basis according to the amount of total battery capacity provided during an event. – Customers should not be allowed participate in both pilots at the same time, to avoid paying customers twice for reducing their demand.
Objectives	– Engage customers who own batteries to provide grid value by delivering peak reduction through battery dispatch aligned with Duke's on-peak rate periods or deployed for demand response events. – Provide incentives to encourage customer use of battery systems to benefit the grid and drive participant bill savings. – Accelerate the integration of DERs that will be essential to meet Duke's clean energy goals. – Provide valuable data on battery performance with various rate plans and DR event strategies.
Measure Life	– 10-year effective useful life (EUL)
Program Intersection with Winter Peak Needs and IRP Filings	– Residential customers (53%) and small/medium business customers (15%) represent about 68% of Duke's total system winter peak demand. Batteries can shift demand either through responding to rate signals or demand response events. – Customer-owned and sited batteries can deliver flexible, distributed, energy storage capacity that can be used as a shared capacity resource. – This is an emerging DER technology that is being adopted by Duke's residential and commercial customers. Duke needs a program designed to access this battery capacity for the benefit of all customers. This program should be designed to ensure that customer batteries are being dispatched and not just sitting idly as a backup power source. – The BYO Battery program can use Duke's existing DER aggregation platform.
Customer Eligibility / Targets	– All single-family residential and small/medium business customers with installed batteries that are compatible with Duke's DER aggregation platform could participate. – We recommend that battery systems should have a nameplate energy rating of at least 9 kWh to participate. – To participate in a load shifting capacity program design, participants would need to be enrolled in a qualifying Duke time differentiated rate plan. Demand response capacity program participants can be on any Duke rate. – Participant batteries must be connected to Duke's DER aggregation platform for the duration of the program.
Incentive Design	– Based upon our experience with other utilities and OEMs, we have not projected costs or incentives for either Pilot at this time. We recommend that Duke conduct further research to determine the value of storage and other co-benefits for all stakeholders before determining benefits and compensation mechanisms. – BYO Battery Load Shifting Capacity Pilot: Duke may consider offering participation incentives in return for: o A three-year commitment to share battery data and dispatch on-peak only o Continuous connection to Duke's DER aggregation platform and commitment to share operational data o Requirement to enroll in a qualifying time differentiated rate plan o No direct utility control of battery operation – BYO Battery Demand Response Capacity Pilot: Duke may consider offering an up-front incentive and a pay-for-performance incentive, in return for: o A one-year commitment to participate in the DR program o Continuous connection to Duke's DER aggregation platform o Commitment to allow direct utility control during DR events
Required Changes to Tariffs or Rates	– Participants in the Load Shifting Capacity Pilot program design must be enrolled in a Duke TOU rate. Participants in the Demand Response Capacity Pilot program design can be served under any rate.
Market Potential and Participation Goals	– Our participation estimates assume a three-year pilot with an overall goal of 3,741 participants and a cumulative 6.9 MW of peak reduction by the end of year three. – BYO Battery Load Shifting Capacity Pilot: assumes 122 participants in year one, 496 in year two, and 1,876 in year three, for a total of 2,494 participants during the three-year pilot. The assumed peak demand savings are 1.6 kW per participant, or 0.2 MW in year one, 0.8 MW in year two, and 2.9 MW in year three, for a total cumulative reduction of 3.9 MW by the end of the three-year pilot. – BYO Battery Demand Response Capacity Pilot: assumes 61 participants in year one, 248 in year two, and 938 in year three, for a total of 1,247 participants during the three-year pilot. The assumed peak demand savings are 2.4 kW per participant, or 0.2 MW in year one, 0.6 in year two, and 2.3 MW in year three, for a total cumulative reduction of 2.3 MW by the end of the three-year BYO Battery DR pilot.
Marketing Plan	– Primary marketing channel is to work with battery storage/solar installers to encourage them to promote the program to customers. – Target outreach to existing battery owners and leverage Duke's website, Online Marketplace, and trade ally partnerships. – Determine potential participants customer journey and opportunities for communications throughout each step of the process including how program participants will be: targeted; solicited; educated about the program; enrolled; incented; engaged throughout the program; surveyed before, during and after equipment installation and program participation; disengaged after the program is complete
Energy Impacts and Winter Peak Demand Savings	– BYO Battery Load Shifting Capacity Pilot: winter peak demand savings are based on an average 1.6 kW reduction per hour during TOU peak periods from a single battery system. (This is 65% of the anticipated kW peak reduction from the BYO Battery DR Pilot Program.) – BYO Battery Demand Response Capacity Pilot: winter peak demand savings are based on an average 2.4 kW reduction per hour during a 3-hour demand response event from a single battery system, assuming participation in at least 10 DR events per year.
Budget	– BYO Battery LS and DR Capacity Pilot Program: We have not projected costs or incentives for either Pilot at this time.

3.3.1 Description

The Bring-Your-Own Battery Pilot Program (BYO Battery) will provide incentives to Duke's residential and small-and-medium commercial business (SMB) customers who own or are purchasing energy storage systems to encourage them to share the capacity of these battery systems for winter peak (and year-round) load shifting and/or demand response capacity.

There are two recommended program designs, both of which could potentially be offered:

- **Load Shifting Capacity Pilot:** offer upfront (and potentially ongoing annual) incentives for customers to enroll batteries in the program and share performance data. Require customers to be on or sign up for a time differentiated rate plan and to commit to dispatch batteries on-peak only.
- **Demand Response Capacity Pilot:** offer an upfront incentive plus a pay for performance incentive for customers to enroll batteries in the program and allow Duke to access battery capacity through DR events and pay incentives according to the amount of battery capacity provided during each event.

Customers should likely not be allowed participate in both pilots at the same time, to avoid paying customers twice for reducing their peak demand.

3.3.2 Objectives

The main objective of this program is to engage customers who own or are purchasing battery storage systems to deliver peak reduction by agreeing to dispatch batteries to align with Duke's peak rates and/or provide battery capacity that can be deployed for demand response events through Duke's DER aggregation platform.

The program has the following additional objectives:

- Targets the use of a distributed energy resource technology that customers are already interested in owning and provides incentives to encourage customer use of these battery systems to benefit the grid
- Accelerates the opportunity for Duke to access and integrate emerging distributed energy resources that will be essential to meet Duke's clean energy goals
- Provides opportunities for Duke to gather valuable battery performance data to learn more about the field operation of battery storage products and allows Duke to see how customer batteries perform in coordination with various rate plans and demand response event strategies

3.3.3 Measure Life

Depending on the number of cycles used and other conditions, typical residential batteries are anticipated to have a measure life of 10 years.

3.3.4 Program Intersection with Winter Peak Needs and IRP Filings

Combined residential customers (53%) and small/medium business customers (15%) represent about 68% of total system winter peak demand in the Duke Carolinas service territory. Customer sited batteries can be used to shift demand to off-peak hours in coordination with time differentiated rates and utility-initiated demand response events controlled through Duke's DER aggregation.

As battery storage technology matures, customer sited batteries can deliver flexible, distributed, energy storage capacity that can be utilized as a shared capacity resource. As batteries are being adopted, Duke should offer a program to access this battery capacity for the benefit of all customers to ensure that customer batteries are being dispatched for system benefit and not just sitting idly as a rarely used backup power source. Duke can use both time differentiated rates and demand response events to ensure that battery dispatch aligns with Duke's winter peak needs and leverage Duke's DER aggregation platform to collect data, dispatch events, and verify performance.

3.3.5 Customer Eligibility / Targets

This program will target residential and small/medium business customers in the Duke Carolinas service territory who have purchased or are purchasing energy storage systems (batteries). Participants must connect to the Duke DER aggregation platform for the duration of the program. Batteries must:

- Be compatible with the Duke DER aggregation platform
- Have an energy rating of at least 9 kWh
- To participate in the load shifting capacity element of the program, participants must enroll in a qualifying time differentiated rate plan

3.3.6 Incentive Design

The Tierra Team did not project potential costs or incentives for this program at this time. We believe that further analysis is needed to determine the value of battery storage and what incentives should be offered when considered holistically in the context of other incentives and compensation mechanisms including rate designs. Duke will need to determine the final exact incentive amounts and design(s) for this program based on appropriate considerations including customer economics and the value of Duke's avoided capacity costs.

There are also significant technical and operational issues to consider while identifying the value of customer-owned battery storage capacity and compensation mechanisms. Residential batteries are an emerging technology which is still far from cost effective due to high upfront costs and long payback periods. And recent product recalls provide evidence that batteries still have technical challenges to address including fire hazard and potential reduced capacity under high ambient temperatures.

While these are significant issues to address, batteries are currently being adopted by Duke's customers and Duke should launch pilots to learn about the technology, how it is used, and the implications for the grid.

Load Shifting Capacity

Duke could offer an upfront incentive for a qualifying battery in return for:

- A three-year commitment to share battery data and to dispatch the battery on-peak only
- Maintaining a continuous connection to Duke's DER aggregation platform to share performance data
- No direct utility control of battery operation

Note that the total incentive amount may be offered upfront or could be divided into an upfront incentive and an ongoing incentive to encourage maintaining program requirements through the three-year duration of each pilot program.

Demand Response – Pay for Performance

Duke could offer an upfront incentive for signing up and connecting to the DER aggregation platform, plus a pay for performance incentive, in return for:

- A three-year commitment to participate in the DR program
- Maintaining a continuous connection to Duke's DER aggregation platform
- Commitment to allow direct utility control during DR events using up to 80% of battery capacity

Pay for performance incentives should be based upon the measured amount of capacity provided by each participating battery system for each DR event scheduled by Duke. Duke will determine the seasons and number of DR events to call. Battery participants can opt out of any event that they do not wish to participate in.

3.3.7 Required Changes to Tariffs or Rates

Participants in the Load Shifting Capacity Pilot must be served under a qualifying Duke time differentiated rate plan for the duration of their participation. Participants in the Demand Response Capacity Pilot can be served under any Duke rate.

3.3.8 Implementation and Operation

- The following steps should be undertaken prior to program launch:
  - Work with EnergyHub or an equivalent DER aggregation platform partner to fine-tune the program strategy, implementation, and operations including the process for enrolling customers, connecting battery storage systems to the platform, tracking participation, and paying incentives
  - Work with battery OEMs and local contractors to confirm the characteristics of qualified batteries installed in the Duke Carolinas service territory
  - Work with local solar/storage installers to inform them about the program, encourage them to promote the program to their customers, and train them how to enroll batteries into the DER aggregation platform
  - Develop training, QA/QC, and commissioning programs
  - Ensure program design aligns with applicable Duke battery interconnection agreements
  - Investigate and address any limitations on batteries exporting to the grid.

3.3.9 Market Potential and Participation Goals

The initial BYO Battery Pilot will run for three years with an overall goal of 3,741 participants from both program element as shown in Table 17 below.

Table 17. BYOB Participation

Pilot Year	1	2	3	Total
BYO Battery Load Shifting	122	496	1,876	**2,494**
BYO Battery Demand Response	61	248	938	**1,247**
TOTAL	**183**	**744**	**2,815**	**3,741**

3.3.10 Marketing Plan

The primary marketing channel will be working with residential battery manufacturers and local battery/solar installers to encourage them to promote the program to their customers and provide them with supporting materials. Other marketing tactics include:

- Use Duke marketing channels to create general awareness about the pilot program along with targeted outreach to existing battery owners and customers who are purchasing battery systems
- Engage battery manufacturers and installers to promote the pilot
- Integrate pilot program offerings into Duke's online marketplace
- Determine how pilot participants will be: targeted; solicited; educated about the program; enrolled; incented; engaged throughout the program; surveyed before, during and after equipment installation and pilot participation; disengaged after the pilot is complete

- Define the survey, contact, specification, installation, commissioning, monitoring, and customer satisfaction assessment processes that will be followed for each installation
- Develop pilot program website content and all customer facing collateral

3.3.11 Measurement & Verification Plan

A detailed Measurement & Verification (M&V) Plan should be developed in coordination between Duke Energy, the DER system aggregator, and Duke's evaluation contractor. The M&V plan should ensure that the program meets targeted utility, customer, and regulatory metrics. Key considerations for the M&V plan include:

- Determine the approach for establishing baselines
- Coordinate the exact battery performance data that will be provided on the DER aggregation platform as a requirement for participation
- Use AMI data where available to verify battery performance data.
  - **Load shifting element** – measure ongoing battery performance, ability to optimize for time-differentiated rate plans, weather data, and non-performance issues
  - **Pay for Performance/Demand response element** – the pay-for-performance program design pays for capacity delivered. Appropriate verification and settlement provision will need to be developed to determine incentive payments

3.3.12 Energy Impacts and Winter Peak Demand Savings

- **BYO Battery Load Shifting Capacity Pilot Program** – customers commit to dispatch batteries only during peak periods. Since this program is intended for monitoring and data collection under time differentiated rates, and since there are no additional incentives or penalties for participation besides the initial signup incentive, we assume that there will be less kW peak reduction that would be experienced under the BYO Battery DR Pilot. For this we assume that customers will generate half of the kW peak reduction that would be gained from the BYO Battery Demand Response Pilot (assumes 80% of 9 kWh energy rated battery = 7.2 kWh / 3 peak hours = 2.4 kW / hour peak reduction available * 65% participation factor = 1.6 kW / hour peak reduction).
- **BYO Battery Demand Response Capacity Pilot Program** – winter peak demand savings are based on an average estimate of 2.4 kW/reduction each hour during a three (3) hour peak event per customer from a single battery system (assumes 80% of 9 kWh energy rated battery = 7.2 kWh / 3 peak hours = 2.4 kW / hour demand reduction). Assumes the program can be used for up to fifty (50) annual DR events, which is a typical annual number of events for energy storage pay for performance programs to date.

3.3.13 Budget

Further research should be conducted before a proposed budget can be developed for the two Pilots.

3.4 HVAC Comprehensive Winter Heating Efficiency Program ('Winter HVAC')

Table 18. Winter HVAC Program At-a-Glance

Description	– Residential space-heating energy efficiency program that provides a coordinated bundle of winter heating related rebates and services for customers. – Leverages existing Duke HVAC related program activities to improve efficiency of existing residential heat pumps, electric furnaces and building envelopes and identifies opportunities for improving heating efficiency to lower winter morning demand.
Objectives	– Strategically deploy energy efficiency upgrades to flatten space heating load during winter peak. – Increase heating and cooling capacity and improve the operating Energy Efficiency Ratio of heat pumps with electric resistance back-up heat source by: o Providing targeted on-site diagnostics that Identify heat pumps with the electric resistance back-up heat source wired to the first stage at thermostat. Encourage these customers to save energy by rewiring it to second stage to use the heat pump mode to cover a greater share of winter heating needs and reduce reliance on lower efficiency electric heat strips. o Improve HVAC system airflow and charge through cleaning the indoor and/or outdoor coils, replacing filters, opening supply registers, increasing return grille/duct size, adjusting indoor blower speed, and correcting the refrigerant charge. – Look for other opportunities to winterize homes, improve heating efficiency, and leverage other Duke efficiency incentives including insulation, air sealing, duct repair, and other HVAC system upgrades.
Measure Life	– Indoor coil airflow improvement – 3-year Effective Useful Life (EUL) – Outdoor coil airflow improvement – 2-year EUL – Refrigerant charge improvement – 10-year EUL – Rewiring electric resistance back-up heat source – 12-year EUL – Early Replacement heat pump – 16-year EUL
Program Intersection with Winter Peak Needs and IRP Filings	– The residential sector accounts for 53% of Duke's total winter peak usage, with all electric homes accounting for a significant majority of winter peak needs. – For homes with residential heat pumps and electric resistance backup heating, the HVAC end use represents approximately 70% of a typical residential dwelling's total coincident demand during critical morning winter peak periods.
Customer Eligibility / Targets	– The Winter HVAC Program will target Single-family and Multi-family residential customers with electric furnaces and heat pumps with electric resistance back-up heat strips. – This program is available for all qualifying residential customers with electric heating; the program is not available to customers with non-electric heat sources.
Incentive Design	– To drive winter peak impacts, one of the most important components of the program is rewiring the electric resistance back-up heat source to stage two on the thermostat. This measure will require a combination of customer education, contractor training, and incentives to drive adoption. o Customers may be reluctant to allow the contractor to rewire the electric resistance backup heat source to stage two on the thermostat without a sufficient financial incentive as well as education on the benefits of this measure. o Participating contractors will need to be trained in customer education and technical support for this measure and should be provided with a direct incentive to encourage them to promote this measure. – Example incentive levels for this program, including both new and existing Duke incentives include: o Winter HVAC Tune-Up: Customer discounted price of $99/unit, and Contractor Incentive of $75/unit. o Adjusting/Re-wiring heat strips: Customer rebate of $75/unit, and Contractor $25/unit. o Install outdoor thermostat: Customer rebate of $75 rebate/unit, and Contractor $25/unit. o Smart thermostat: Customer rebate of $50/unit. o Heat Pump Replacement: Customer rebate of $350/unit for air source and $400/unit for geothermal. – To increase participation in targeted winter peak locations (i.e., DEP West), Duke could also offer enhanced incentive levels and/or additional HVAC measures such as cold climate heat pumps. – Work with home performance contractors to bundle rebates for thermal envelope improvements.
Required Changes to Tariffs or Rates	– This program does not require any changes to tariffs or rates.
Market Potential and Participation Goals	– Residential Appliance Saturation Study findings show that 52% of homes use only electricity for heating with 8% using electric resistance heating and 44% using heat pumps with backup electric strip heaters. We estimate the systemwide technical market for residential heat pumps in 2021 to be 1,690,553 units. The participation goal for this program is approximately 12,500 homes/year and expected to grow steadily over five years to 25,000/year.
Marketing Plan	– The primary marketing strategy should leverage relationships with existing HVAC trade allies to take advantage of the HVAC contractors' constant contacts with thousands of customers in need of the measures in the Program. – Participating HVAC contractors should be allowed to market the program to their customer base using Duke Energy approved marketing materials. – The program should be supported by broad scale marketing and outreach efforts to engage customers and educate them about the program. Accordingly, the program should feature customer marketing, education, and awareness building efforts. – Integrate applicable measures into the Online Marketplace and use the platform to advertise the program to customers who purchase related items (e.g., the benefits of participating in a comprehensive tune-up could be advertised to customers purchasing a smart t-stat via the Online Marketplace). – Duke should promote the program heavily prior to the winter season and develop a list of participating HVAC contractors that customers can select. As soon as possible after launch, update marketing materials to incorporate positive customer experience testimonials and energy/bill savings case studies from participants.
Energy Impacts and Winter Peak Demand Savings	– Demand savings in this program will vary widely based on the exact energy efficiency services performed at each participating home. For modeling purposes, we assume the average program participant achieves coincident winter peak demand savings at 7:00 a.m. ranging between 0.12 to 0.35 kW per system, depending on system efficiency, dwelling type and occupant use patterns. – Based on these assumptions, the Program can deliver between 2.3 and 2.6 MW of peak reduction by 2022 and 8.3 MW by 2041.
Budget	– Estimated first year program costs are expected to total $1,212,500.

3.4.1 Description

The HVAC Comprehensive Winter Heating Efficiency Program is a residential space-heating energy efficiency program that will provide a coordinated bundle of rebates and services for customers (which will leverage existing Duke HVAC related program activities) to make improvements to existing residential heat pumps and furnaces and identify other opportunities for improving heating efficiency and lowering winter morning demand, including duct repair and thermal envelope improvements. In particular, the program will target residential customers who have heat pumps with an electric resistance back-up heat source to improve efficiency by adjusting heat strip control settings to reduce the use of electric resistance heating.

The HVAC Winter Program will also provide incentives for qualified HVAC contractors to help customers make other cost-effective efficiency improvements to their heat pumps and furnaces that will reduce energy usage and winter peak demand. Duke should coordinate this effort with existing HVAC program implementation activities to:

- Recruit, enroll, train, and certify a pool of HVAC contractors and their service technicians to provide program services. This should heavily leverage Duke's existing network of trade allies promoted through its Find it Duke contractor referral service.
- Create a customer awareness campaign and promote the program to customers in targeted areas; including those with large quantities of older furnaces and heat pumps, locations that do not have natural gas service, and potential grid constrained localities. The program should also be promoted through the existing complementary Smart $aver Program, which can channel customers that aren't interested in Early Replacement of their HVAC system into participating in a tune-up.
- Provide robust program Quality Assurance and Quality Control and customer follow-up to gauge customer satisfaction and encourage customers to participate in other Duke Energy programs to further reduce their winter peak demand, including enrolling the customers in the Duke Energy winter peak focused demand response smart thermostat program.
- Market to customers purchasing applicable products such as smart thermostats through Duke's Online Marketplace.

3.4.2 Objectives

The HVAC Winter Program is a new residential DSM offering that will strategically deploy energy efficiency upgrades to flatten space heating load during winter peak. The rationale for implementing this program is to provide peak focused energy efficiency savings for residential heating end uses that are most coincident with Duke's winter peak needs. The program seeks to improve energy efficiency through a targeted strategy that includes the following tactics:

- Increase heating and cooling capacity and improve the operating Energy Efficiency Ratio of heat pumps with electric resistance back-up heat source by providing tune-ups that:
  - Identify heat pumps with the electric resistance back-up heat source wired to the first stage at thermostat and encourage these customers to save energy by rewiring it to second stage which will use the heat pump mode to cover a greater share of winter peak heating needs and reduce reliance on lower efficiency electric resistance heat strips.
  - Install outdoor thermostats that lock out electric resistance backup heat at mild outdoor conditions, or properly adjust existing outdoor thermostats to prevent unnecessary heat strip use during times that the compressor can meet the heating load.
  - Assess real HVAC performance through detailed testing and diagnostics where appropriate.
- Improve HVAC system airflow and charge through measures such as:
  - Cleaning the indoor and/or outdoor coils

- Replacing filters
- Opening supply registers
- Increasing return grille/duct size
- Increasing indoor blower speed
- Correcting the refrigerant charge

- Identify operational heat pumps with low operating efficiency as targets for Early Replacement by channeling those customers into the Smart $aver Program to one of the following existing offerings:[33]
  - 15 and 16 SEER Heat Pump with ECM and smart thermostat ($350 rebate)
  - 17 Seer Heat Pump with ECM and smart thermostat ($450 rebate)
  - 19 EER Geothermal heat Pump with ECM and smart thermostat ($450 rebate)
- Leverage Duke's existing HVAC programs and services to recruit customers for the Comprehensive HVAC program, including:
  - The DEP and DEC Residential Smart $aver Programs which currently provides residential single-family customers with incentives to purchase high efficiency Heat Pumps and smart thermostats.
  - The DEP and DEC Multi-family Energy Efficiency Programs, which are currently used as an alternative delivery channel targeting multi-family apartment complexes
  - The DEP and DEC's Find it Duke contractor referral service which provides customers with an interactive online form to find a qualified contractor from Duke's managed network, who are approved to perform services that will qualify for a rebate
  - Customers participating in the HVAC Winter Program who have manual and programable thermostats or would benefit from duct sealing and attic insulation
  - Smart thermostats capable of providing event-based winter peak demand response capacity.
- Channel HVAC Winter Program participating customers who receive a smart thermostat rebate or already have a smart thermostat into the new winter rate offerings (i.e., New Time-of-Use, Peak Time Rebate, and Critical Peak Pricing) and winter peak BYOT demand response program proposed in this study.

3.4.3 Measure Life

The following list provides the estimated effective useful life for the measures offered through the HVAC Comprehensive Winter Heating Efficiency Program:

- Heat Pump and Furnace Tune-ups[34]
  - Indoor coil airflow improvement – 3 years
  - Outdoor coil airflow improvement – 2 years
  - Refrigerant charge improvement – 10 years[35]
  - Rewiring electric resistance back-up heat source – 12 years
- Smart thermostat – 11 years[36]

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[33] Duke Energy, Smart $aver Program. https://www.duke-energy.com/home/products/smart-saver/hvac-install

[34] Tune-up measure EULs not sourced from the Arkansas TRMv.8.1 are based on engineering best judgements from Proctor Engineering Group.

[35] Arkansas Public Service Commission, *Arkansas TRM Version 8.1 Vol. 1*, August 31, 2019. Page 51.

[36] Arkansas Public Service Commission, *Arkansas TRM Version 8.1 Vol. 1*, August 31, 2019. Page 84.

- Early Replacement heat pump – 16 years[37]

3.4.4 Program Intersection with Winter Peak Needs and IRP Filings

The residential sector accounts for 55% of total system demand between 7:00 a.m. through 9:00 a.m., with all-electric homes accounting for a significant majority of winter peak needs.[38] The winter peak characterization indicates that for homes with residential heat pumps and electric resistance backup heating, the HVAC end use represents approximately 70% of a typical residential dwelling's total coincident demand during Duke Carolinas critical morning winter peak periods. This makes residential electric heating an essential targeted end use for Duke's winter peak focused EE/DSM programs.

3.4.5 Customer Eligibility / Targets

The HVAC Winter Program will target four distinct market opportunities:

- Single family residential customers:
  - Heat pumps with electric resistance back-up heat strips
  - Electric furnaces
- Multifamily residential customers:
  - Heat pumps with electric resistance back-up heat strips
  - Electric furnaces

This program is available for all qualifying residential customers with electric heating; the program is not available to customers with non-electric heat sources.

3.4.6 Incentive Design

For the HVAC winter program to be successful, the program must be attractive to participating HVAC contractor trade allies who will drive program participation and savings impacts. The program rebates and incentives need to be set at a level high enough to be attractive to the HVAC contractors in Duke Energy's service territory, and participating contractors must be allowed to charge their normal market rate fees for their services.

To be most convenient and helpful for participating customers, incentives should be paid as an instant rebate that is directly provided as a line-item deduction on the customers invoice at the time of service. Participating contractors should be paid promptly for all instant rebates provided to their customers once Duke verifies eligibility. Additionally, Duke should consider offering a bonus incentive for early replacement, particularly if Duke can claim additional savings for these units. A kicker incentive may also be offered in select regions, such as the DEP West area, to promote adoption of cold climate heat pumps meeting Energy Star version 6.0 (draft) specification for low temperature performance which include the following specifications:

- Heating capacity at 5 °F must be at least 70% of capacity at 47 °F
- COP ≥ 1.75 at 5 °F

To drive winter peak impacts, the most important component of the program is the rewiring of the electric resistance back-up heat source to stage two on the thermostat. This measure will require a combination of

[37] Arkansas Public Service Commission, *Arkansas TRM Version 8.1 Vol. 1*, August 31, 2019. Page 67.

[38] Tierra Resource Consultants, *Winter Peak Analysis and Solution Set.* Page 9.

customer education, contractor training, and incentives to drive adoption. Customers may be reluctant to allow the contractor to rewire the electric resistance backup heat source to stage two on the thermostat without a sufficient financial incentive as well as education on the benefits of this measure. Participating contractors will need to be trained in customer education and technical support for this measure and should be provided with a direct incentive to encourage them to promote this measure. Table 19 below details the incentive design for the measures proposed in the Program.

Table 19. HVAC Winter Program Incentive Design

Item	Customer	HVAC Contractor
Winter HVAC Tune-Up (Base)	• Discounted price of $99/unit	• Incentive of $75/unit completed
Adjusting/Re-wiring heat strips*	• $75 rebate/unit	• $25/unit incentive • Can charge for this service
Install outdoor thermostat*	• $75 rebate/unit	• $25/unit incentive • Can charge for this service
Smart thermostat	• $50 rebate/unit	
Heat Pump	• $350 for air source heat pump • $400 geothermal heat pump • Offer additional incentives in targeted locations (i.e., Cold-Climate) Heat Pumps in DEP West). • Could also offer added incentives for early replacement.	
Quality Installation and Maintenance		• Up to $75/unit for meeting quality installation and maintenance standards
Ductwork Sealing	• Up to $100 for reducing duct leakage by a minimum of 12%.	
Thermal Envelope	• Up to $250 for attic Insulation and attic air sealing. Attic insulation must be improved from R-19 or below to at least R-30, and home leakage rate must be improved by at least 5%. • Where possible, work with comprehensive home performance contractors to bundle rebates for thermal envelope improvements.	

* These incentives cannot be combined; participating HVAC units are eligible to receive either the heat strip adjustment or outdoor thermostat measure only (not both).

3.4.7 Required Changes to Tariffs or Rates

This program does not require any changes to tariffs or rates. It is focused on reducing residential winter energy usage during peak demand periods, so it is a program that can provide additional cost savings benefits for customers who choose Time of Use rates and other innovative time differentiated rate designs, but it does not require a customer to participate in any specific rate or tariff to take advantage of the program.

3.4.8 Implementation and Operation

The following steps should be undertaken prior to program launch:

- Fully integrate the program into Duke's existing Find it Duke contractor referral system
- Coordinate with local HVAC contractors prior to finalizing the program design to gauge contractor interest and barriers to participation and get their input on the final program design details

- Develop final program design, program standards and requirements, and HVAC contractor participation agreements
- Develop program website content and all customer facing collateral, including customer educational materials and contractor handouts to promote the benefits of proper heat strip adjustment
- Contract with a program implementer to help operate and support the program (either a new implementer or an extension of current implementer scope)
- Recruit an appropriate number of HVAC contractors to meet customer demand and Duke Energy participation goals

The following program quality control elements should be included to ensure positive customer experiences and measurable impacts are achieved:

- Quality installation and maintenance criteria should be applied to all HVAC contractor work in the program. Participating HVAC contractor personnel should be required to use procedures that check and record the data they gather on the system while on site. This may include a review of what virtual energy assessment tools currently being used in similar programs could be deployed.
- To be eligible to receive program rebates, customers with an electric resistance back-up heat source wired to stage one at the thermostat must agree to have their system rewired to the correct configuration of having the electric resistance back-up heat source wired to stage two at the thermostat
- The program implementor must conduct quality control and assurance reviews to ensure that all data collected by the HVAC contractor personnel is accurate and reasonable
- Field based quality control of the HVAC contractor personnel's work needs to be inspected with the quality control personnel duplicating and confirming the test results reported
- Prior to participation, all HVAC service personnel in the program need to complete program training that covers required technical and customer experience elements of the program

The program incentive fulfillment structure will consist of:

  - Participating contractors agree to offer instant rebates – where the value of Duke incentives is instantly deducted from the total purchase price. This design will encourage greater customer participation.
  - The program implementer should set up an easy access on-line portal for HVAC contractors to submit incentive applications and need to be paid promptly for all the customer rebates they have provided and incentives they have earned
  - Multifamily complexes should be pre-screened prior to inclusion in the program to determine if there are issues with the wiring of the electric resistance back-up heat source, the complex is a good candidate for smart thermostats, and management is willing to allow the thermostats to be rewired or smart thermostats be installed

3.4.9 Market Potential and Participation Goals

RASS findings from 2016 and 2019 surveys in DEC and DEP territories show that 52% of homes use only electricity for heating with 8% using electric resistance heating and 44% using heat pumps with backup electric strip heaters. Based on our analysis, the Tierra team estimates Duke Carolina's systemwide technical market for residential heat pumps in 2021 to be 1,690,553 units. The participation goal for this program is approximately 12,500 in year one and expected to grow over five years to steady state of approximately 25,000/year.

We do not currently have data on the saturation of specific HVAC unit configurations to define the exact percentage of all-electric residential customers with supplemental heat strips. However, during the average winter peak event for DEC in 2018 we estimate the total heat load for homes with electric heating to be about 2,500 MW. This is made up of about 1,500 MW (60%) from heat pump condensers and about 1,000 MW (40%) from electric resistance heating which includes 1) supplemental heat strips on heat pumps, 2) electric wall furnaces, 3) electric baseboard heaters, and 4) small supplemental plug-in heaters. We were unable to isolate the exact contribution from supplemental heat strips on heat pumps, but consider it to be significant, between one to two thirds of the electric resistance heating load, or 300 to 600 MW. For DEP we estimate the total heat load for homes with electric heating to be about 1,500 MW for the average winter peak day, made up of about 900 MW from heat pump condensers and about 600 MW from electric resistance heating. Like DEC, our estimate is that supplemental heat strips on heat pumps account for about 180 MW to 360 MW of resistance heating load with electric wall furnaces, electric baseboard heaters, small supplemental plug-in heaters accounting for the balance. Note that these estimates represent the average of 6 winter peak events in 2018; annual system winter peak would be somewhat higher, but we expect that the distribution of electric heating load between heat pump condensers and other electric resistance heating remains constant.

3.4.10 Marketing Plan

The HVAC Comprehensive Winter Heating Efficiency program's primary marketing strategy will be to leverage Duke's existing HVAC trade ally relationships to engage HVAC contractors to offer this program to their customers. This takes advantage of the HVAC contractors' constant contacts with thousands of customers in need of the measures in the Program. Participating HVAC contractors should be allowed to market the program to their customer base using Duke Energy approved marketing materials. The marketing plan should include training and education of HVAC contractor personnel on the benefits of the program and provide them with approved program messages.

The program also requires broad scale marketing and outreach efforts to engage customers and educate them on the program and other Duke energy efficiency programs. Accordingly, the program should feature customer marketing, education and awareness building efforts, including but not limited to:

- Public relations campaigns at the start of winter season to generate free media attention for the program
- Advertising campaign to send a controlled message to the marketplace
- Duke Energy customer bill inserts
- Customer educational materials and contractor handouts that promote the benefits of proper heat strip adjustment
- Media coverage from local television and radio stations
- Duke Energy Online Marketplace and website
- Electronic social media (Facebook, Twitter, YouTube, etc.)
- Community outreach events

As part of these marketing efforts, Duke should promote the program heavily prior to the winter season and have a way for customers to select from a list of participating HVAC contractors. As soon as possible after program launch, Duke should update marketing campaigns and materials to incorporate positive customer experience testimonials and energy/bill savings case studies.

3.4.11 Measurement & Verification Plan

An evaluation plan should be clearly defined prior to pilot implementation to ensure that all necessary data is collected. These efforts should be coordinated with Duke's evaluation contractor and should include, but not be limited to, the following:

- A kick-off meeting between Duke, implementers, and evaluators to ensure all data needed for evaluation is gathered, will be complete, and will accurately reflect field activities
- Ongoing solicitation of customer and HVAC contractor feedback via surveys to help refine program outreach and delivery mechanisms based on lessons learned
- Detailed impact and process evaluations of program activities, particularly during the first year, to determine program effectiveness both at reducing peak and engaging customers and HVAC contractors. Adjustments should be made quickly as lessons are learned from the impact and process evaluations.
    - Impact evaluations needs to include onsite measurement and short term/long term monitoring for HVAC measures to establish savings and demand reduction as well as engineering estimates

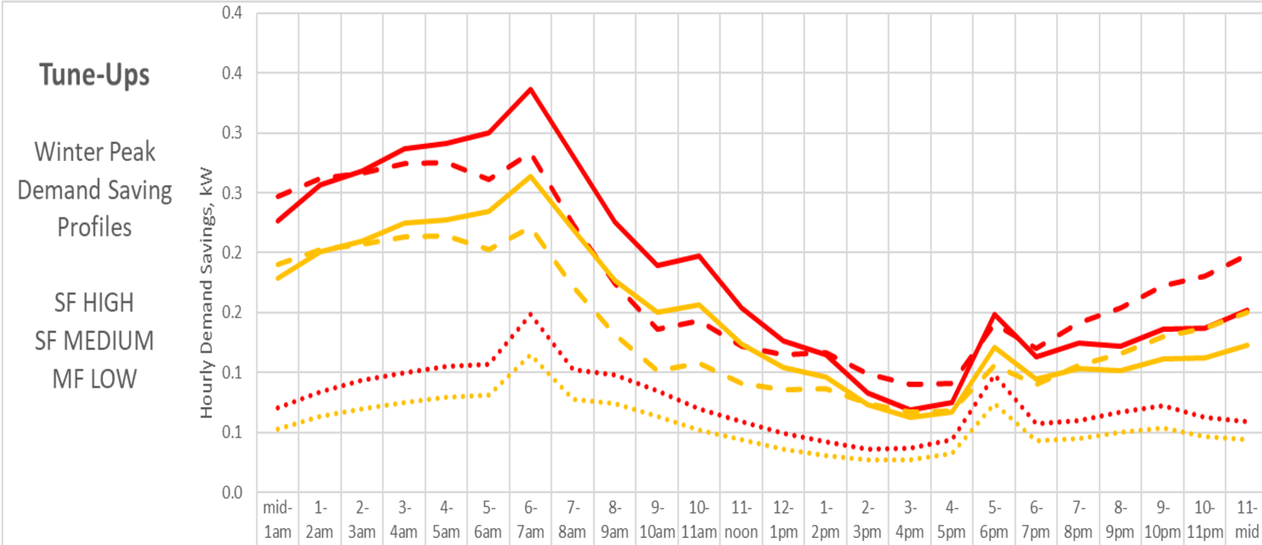
3.4.12 Energy Impacts and Winter Peak Demand Savings

The Tierra team used BEopt to estimate demand savings potential from tuning-up heat pumps, including the effect of adjusting strip heat controls. Figure 3 provides our estimate of savings for various heat pump performance factors and indicates that demand savings at 7:00 a.m. ranges between 0.12 to 0.35 kW per system, depending on heat pump system efficiency, dwelling type and occupant usage patterns. [39] According to the Tierra team's modeling results detailed in the Winter Peak Demand Reduction Potential Assessment, the HVAC Winter Program could deliver between 2.3 and 2.6 MW of peak reduction by winter 2022 and 8.3 MW by 2041. Our modeling assumptions for this program include:

- Costs annual growth of 2%
- Technical Market of 1,690,553 units
- Current installed base of 0
- 12,500 participants in year 1
- Reach steady state of approximately 25,000/year at year 5, not accounting for customer growth

[39] Proctor Engineering, *Residential HVAC Winter Peak Demand Reduction Opportunities*.

Figure 3. Estimate of Winter Heat Pump Tune-up Savings



	mid-1am	1-2am	2-3am	3-4am	4-5am	5-6am	6-7am	7-8am	8-9am	9-10am	10-11am	11-noon	12-1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6-7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-mid
High - HSPF 6.2 - Tune-Up	0.23	0.26	0.27	0.29	0.29	0.30	0.34	0.28	0.23	0.19	0.20	0.15	0.13	0.11	0.08	0.07	0.07	0.15	0.11	0.12	0.12	0.14	0.14	0.15
Med - HSPF 6.2 - Tune-Up	0.25	0.26	0.27	0.27	0.28	0.26	0.28	0.22	0.17	0.14	0.14	0.12	0.12	0.12	0.10	0.09	0.09	0.14	0.12	0.14	0.15	0.17	0.18	0.20
Low - HSPF 6.2 - Tune-Up	0.07	0.08	0.09	0.10	0.10	0.11	0.15	0.10	0.10	0.08	0.07	0.06	0.05	0.04	0.04	0.04	0.04	0.10	0.06	0.06	0.07	0.07	0.06	0.06
High - HSPF 7.7 - Tune-Up	0.18	0.20	0.21	0.22	0.23	0.23	0.26	0.22	0.18	0.15	0.16	0.12	0.10	0.10	0.07	0.06	0.07	0.12	0.09	0.10	0.10	0.11	0.11	0.12
Med - HSPF 7.7 - Tune-Up	0.19	0.20	0.21	0.21	0.21	0.20	0.22	0.17	0.13	0.10	0.11	0.09	0.09	0.09	0.07	0.07	0.07	0.11	0.09	0.11	0.12	0.13	0.14	0.15
Low - HSPF 7.7 - Tune-Up	0.05	0.06	0.07	0.08	0.08	0.08	0.12	0.08	0.07	0.06	0.05	0.04	0.04	0.03	0.03	0.03	0.03	0.07	0.04	0.04	0.05	0.05	0.05	0.04

3.4.13 Budget

The following estimated program budget is based on the preliminary program design concept as discussed above and the Tierra team's years of experience in program design.

Our suggested first year program budget assumes:

- 12,500 participants
- Base HVAC Tune-Up Incentive of $75/unit
- Incremental Measure Cost of $175, [40] resulting in a discounted customer price of $99/unit

The total program budget will be scaled to the cost of rebates and incentives, which are detailed in Table 20 below.

Table 20. HVAC Winter Program Estimated First Year Rebate and Incentive Costs

Rebate/Incentive	Quantity	Value per Unit	Total Cost (Year 1)
Winter HVAC Tune-Up (Base)	12,500	$75	$937,500
Adjusting/Rewiring Heat Strips	12,500	$100	$125,000
Total			**$1,062,500**

Estimated first year program costs, including rebates/incentives and program administration, are presented in Table 21.

[40] Missouri Technical Reference Manual.

Table 21. HVAC Winter Program Estimated First Year Budget

Budget Category	Percentage	Year 1 Cost
Rebates and Incentives	51%	$1,062,500
Program Implementation	35%	$740,000
Program Marketing and Outreach	7%	$150,000
Planning and Administration	7%	$150,000
Total	**100%**	**$ 2,102,500**

3.5 Connected Water Heater Controls Program ('Connected WH')

Table 22. Connected Water Heater Controls Program-At-a-Glance

Description	– Residential load shifting program that uses connected water heaters controls. – Promotes retrofit water heater controls and new replacement connected water heaters. – Leverages the thermal storage potential of residential water heaters to provide peak demand reductions and customer bill savings in coordination with time differentiated rates.
Objectives	– Provides dynamic connected water heater controls optimized to work with Duke's TOU rate structure. Automates water heating load shifting around Duke's TOU on-peak periods, resulting in year-round energy and bill savings for customers while reducing peak demand. – Utilizes water heating as a grid resource for winter peak demand reduction. Can also shift water heating energy use to better align with renewable energy production to help meet Duke's clean energy goals. – Offers an opportunity for limited income households, multi-family properties and other customers to use a low-cost energy storage and load shifting technology to benefit with time differentiated rates.
Measure Life	– 13 Year Effective Useful Life (EUL)
Program Intersection with Winter Peak Needs and IRP Filings	– Based on energy simulation models that were calibrated to Duke's load forecasts and appliances saturation surveys, water heating represents an average of about 10% of the peak demand of an all-electric home during morning Duke Carolina's winter peak periods.
Customer Eligibility / Targets	– Residential customers interested in a retrofit device on their water heater that is programmed to save money on a time differentiated rate plan – the program can target current TOU participants as well as new rate opportunities with new participants. – Single-family homeowners who currently or will soon need a replacement water heater that can be upgraded to a connected unit. – Multifamily properties where retrofit water heating controls can be installed throughout the community to rapidly scale penetration. – New home communities, working to install connected water heaters in cooperation with participating homebuilders. – Trade allies comprised of local plumber, retailers, and distributors who are often the first point of contact when a water heater fails.
Incentive Design	– For existing SF homes, provide incentives of $75/unit. Or consider offering free retrofit controls for qualifying limited income households and/or as an incentive for customers who enroll in innovative rate plans. – In the multi-family program, complete a direct install of connected water heater controller retrofits at a cost of approximately $200/unit (including product and installation). – For the new homes program, offer an incentive of $100/home for builders who install new connected water heaters in their homes. – Retrofit connected controls and new replacement connected water heaters can be promoted on the online marketplace and through participating home performance contractors. They can also be direct installed through the multifamily and limited income programs. – Retrofit connected controls range in price from $100-$200/unit plus install, and the incremental cost of including connected controls on a new water heater is approximately $90.
Required Changes to Tariffs or Rates	– Connected water heaters can be optimized to work with a variety of different innovative time differentiated rate plans including TOU, demand, CPP and other rates.
Market Potential and Participation Goals	– We estimate Duke Carolina's systemwide market viable units in 2021 to be 1,384,799. This program will take some time to build awareness and grow participation. Accordingly, our anticipated first-year participation goal for this program is 3,140 growing to approximately 33,344 over a 10-year period.
Marketing Plan	– For existing SF homes, market this technology as part of home performance retrofits; promote incentives on the online marketplace. Work with local trade allies and distributors. – For the multifamily program, market this technology as part of the overall multifamily direct install program in conjunction with TOU rate options. – For the new homes program, market to homebuilders as part of overall residential new construction program offerings. – Work with trade allies to integrate program marketing with their current marketing initiatives and coordinate with manufacturers to conduct contractor trainings. – Use a combination of marketing, agreements, and upstream or midstream incentives with manufacturers, distributors, and contractor trade allies, to guarantee that water heating controllers will be bundled with water heater replacements, tune-ups and other smart technologies. – Advertise participating retailers and contractors on Duke's online store, website, and social media channels.
Energy Impacts and Winter Peak Demand Savings	– Potential to deliver up to 2.2 MW of peak reduction by 2022 and 26.2 MW by 2041.
Budget	– Estimated first year program costs are expected to total $706,500.

3.5.1 Description

The Connected Water Heater Controls ('Connected WH') Program is a residential water heating load shifting program that will offer discounted retrofit water heater controls and replacement connected water heaters to leverage the low-cost thermal storage potential of water heaters. These devices can be installed on electric water heaters or built into new units and programmed to respond to Duke's time-of-use and other variable pricing rates to automatically shift load to off-peak periods and save customer energy costs while also shifting energy use to reduce peak demand and better align energy use with solar production to help meet Duke's clean energy goals. Duke will work with trade allies to install these rate-enabled, connected water heater controls on existing and newly installed electric water heaters that are optimized to work with Duke TOU rate periods for year-round peak demand/energy savings. The units may be discounted and/or provided for free with direct installation to customers who are enrolled in a qualifying time differentiated rate plan.

3.5.2 Objectives

The Connected WH program is an integrated DSM offering that will deploy control technologies capable of delivering multiple benefits including energy efficiency, load shifting and demand response capacity savings that help address the current and future needs of Duke's winter peaking electric grid.

The objectives for implementing this program include:

- Help residential customers conveniently manage their water heating energy use to reduce peak demand (especially during winter morning peaks) without sacrificing comfort or performance
- Provide residential customers with dynamic controls that can be coordinated to work with Duke's TOU rate structure to automate the shifting of water heating demand around Duke's TOU on-peak periods, resulting in year-round energy and bill savings for customers
- In addition to rate enabled load shifting, connected water heating controls could be aggregated in Duke's DER platform and used in demand response events as a grid resource for winter peak demand reduction during critical peak hours, with minimal incremental effort due to having the same hardware and technological infrastructure that is required for load flattening/management
- Promote peak demand reductions and bill savings opportunities for residential customers by enrolling in Duke's time differentiated rates
- Opportunity to partner with residential property management companies in Duke's territories to incorporate rate-enabled connected water heating controllers into their rental properties 'at scale' to drive rapid penetration/scale of residential DR/load shifting capacity
- Potential for additional value from connected water heating to deliver other ancillary grid services such as local frequency response and balancing services in the form of quick load increases and decreases

3.5.3 Measure Life

According to the Arkansas Technical Reference Manual, the estimated useful life is 13 years for electric storage tank water heaters and 10 years for heat pump water heaters. The measure life for connected water heater controls is assumed to be the same as the useful life of a water heater.

3.5.4 Program Intersection with Winter Peak Needs and IRP Filings

The winter peak characterization assessment indicates that water heating represents about 10% of typical electric home peak demand during Duke's winter peak periods. Smart controllers can shift electricity usage to off peak hours without impacting hot water availability, so they can be an important technology to include in Duke's winter peak focused energy efficiency and demand side management programs.

By combining water heater controls with time differentiated rates, the controls can be optimized to pre-heat water prior to the morning peak demand period to save participant energy costs while also reducing the winter peak. In addition, after the morning usage period, the water heaters can be deployed in late morning/early afternoon to use energy during the peak solar production period that can be stored for later use. This helps flatten system load shapes and helps integrate more solar energy to meet clean energy goals. In addition, connected controls can also enable water heaters to be used for demand response events.

3.5.5 Customer Eligibility / Targets

The primary target markets for the Connected Water Heater Controls Program will consist of:

- Residential customers with electric water heating who would want a retrofit device on their water heater that is programmed to save them money on a TOU rate plan. This includes customers already enrolled in a TOU rate plan and/or demand response programs as well as customers that inquire about ways to reduce their bills.
- Single-family or multi-family homes who currently or will soon need a replacement water heater and thus can be more easily channeled into the program through the purchase of a new replacement water heater that includes connected controls. Duke should include qualifying connected water heaters and retrofit controls into Duke's Online Savings Store.
- Trade allies comprised of local plumber, retailers, and distributors who are responsible for getting water heaters the "final mile", and into the customers' hands. Reaching these targets is essential to the program because they are often the first point of contact when a water heater fails, and their recommendations tend to be trusted by customers who are generally unfamiliar with the water heating market. Duke should leverage its existing trade allies who are already familiar with marketing Duke programs to encourage their customers to install connected water heater controls.

Participants should meet the following basic requirements to be eligible to participate in the program:

- Must be an existing Duke Residential customer with electric water heating
- Single-family homes must have wi-fi connectivity, while multi-family homes may utilize dedicated cell or wi-fi to provide consistent community wide coverage as tenants move in and out
- Must be enrolled or sign-up for a qualifying time differentiated rate plan
- Must be installed by a licensed contractor. Duke may consider requiring customers to use only participating contractors.
- Both retrofit devices on an existing tank and new connected water heater replacements that include connected controls are eligible
- Limited to electric tank storage-style water heaters (i.e., electric resistance) of at least 35 gallons or more

3.5.6 Incentive Design

The cost of connected water heaters and controls can vary considerably depending on the final manufacturer specifications and delivery approach decided on for the Connected WH program. Our proposed approach for Single Family retrofit controls and new replacement connected water heaters is to promote them through the online marketplace and participating home performance contractors and limited income programs. Retrofit controls range in price from $100-$200/unit plus install, and the incremental cost of adding connected controls to a new water heater is approximately $90. Duke will provide incentives of $75/unit and may offer free connected controls for qualifying limited income households and potentially as a reward for switching to innovative rate plans. Direct install of connected water heater controller retrofits in the Multi-family sector cost approximately $200/unit (including product and installation). For the new homes program, Duke will offer an incentive of $100/home for builders who install wi-fi connected water heaters in their homes.

In the future, we recommend a program design where water heater controllers and connected water heaters purchased on the online marketplace can be pre-enrolled in any future demand response programs compatible with water heaters, as this is a best practice that can significantly increase the percent of smart devices that become enrolled in demand response. If a customer enrolls their water heater in a demand response program, we recommend that the customer receive an ongoing participation reward, an incentive typically provided on an annual basis in exchange for the customer allowing the utility to access and control their water heater, similar in design to the smart thermostat BYOT DR program. The primary benefits of grid-interactive functionality and load shifting are to the grid and Duke, so this type of customer ongoing participation reward ensures that the customers are compensated for giving Duke access to control their water heaters.

3.5.7 Required Changes to Tariffs or Rates

Connected water heaters can be optimized to work with a variety of different innovative time differentiated rate plans including TOU, demand, CPP and other rates.

Although not necessary for launching the Connected WH program, the introduction of a fixed-bill subscription plan as described previously in section 2.3 would benefit Connected WH program by expanding the opportunity for customer classes such as low-moderate income customers and small businesses, which typically are less likely to participate in demand response programs due to non-performance risk, to participate. The DER aggregation platform, smart device installation procedures, and other infrastructure developed in the Connected WH program can be leveraged by the fixed-bill subscription plan, reducing costs and easing the deployment process. In addition to using smart thermostat data from the Connected WH program to target homes that are the best candidates for the subscription plan.

3.5.8 Implementation and Operation

The winter peak characterization assessment included a review of various studies defining load shapes for electric water heaters as well as a development of a BEopt energy simulation model that disaggregated energy use for typical all electric homes, which showed that electric water heating has a typical morning and evening dual peak. In general, these studies show weekday peak loads between 0.7 and 1.0 kW per unit occurring between 7:00 and 9:00 a.m. Based on these findings and the proposed new TOU rates that the controllers will be optimized to, the following are the general control parameters for connected water heating controllers:

- Water heater operation will be optimized by the dynamic rate-enabled controls which are designed to operate in coordination with Duke's on-peak rate schedules. This will ensure that load shifting occurs to reduce demand on non-holiday weekdays during the 6 to 9 a.m. morning peak.
- In the future, water heaters could be aggregated with other distributed energy resources within Duke's DER aggregation platform. Currently, Rheem connected water heaters are integrated with the EnergyHub platform but currently no APIs have been developed to connect retrofit water heater controls. Additional value could be gained from incorporating connected water heating into existing and newly proposed demand response programs once this capability is realized.
- During implementation, water heater controls could be packaged with rate enabled smart thermostats whenever possible to provide greater year-round load shifting capabilities.

For existing single-family homes, units can be promoted through the online marketplace with an 'all in' fulfillment, including the controller and install. Duke would provide the controllers and use its network of trade allies to install these units at an agreed upon price. As is currently allowed in the Multifamily Programs, Duke can also allow property managers of multi-family apartments to use their maintenance team or contractor to do the installs, with Duke's program administrator overseeing training, supervision, verification and quality assurance inspections. For the Income Qualified Programs, they can be directly installed during the audit

3.5.9 Market Potential and Participation Goals

Our review of the 2019 Residential Appliance Saturation Study indicates that 71% of HWH is electric and that 86% of rental units are electric hot water heaters, vs. 67% for owner occupied dwellings, as shown in Table 23. Table 24 further breaks down water heat fuel by dwelling type, further defining high saturation in the rental market, especially dwellings with 3 or more units. Our analysis also found that 98% of water heaters have a tank (resistance or HP).

Table 23. Water Heat Fuel Type by Resident Type

Resident Type	Electric	Natural gas	Resident Total
Owner	67%	33%	100%
Renter	86%	14%	100%

Table 24. Water Heat Fuel by Dwelling Type

Resident Type	Fuel Type	Single-family detached	Single-family attached	Duplex	Condo	Apartment (3-4 units)	Apartment (5 or more units)	Mobile home
Owner	Electric	64%	50%	60%	76%			100%
	Natural Gas	36%	50%	40%	24%			0%
Renter	Electric	76%	82%	81%	84%	89%	91%	100%
	Natural Gas	24%	22%	19%	16%	11%	9%	0%

As discussed in more detail in the Winter Peak Analysis and Solution Set report, technical demand is defined as the MW that would result if all electric hot water heaters were operating at the same time. Table 25 indicates technical system demand of 2,147 MW based on 71% of all how water heating systems being electric and water heating representing about 10% of electric home demand during peak load periods where appliances and heat pumps are also operating coincident with the water heater.

Table 25. Residential Dwelling and Electric Water Heater Technical Demand

Dwelling Type	System	DEC	DEP
2 units	44	28	17
3 or 4 units	60	37	22
1-unit, attached	84	52	32
10 to 19 units	88	54	34
5 to 9 units	92	57	35
20 or more units	96	60	36
Mobile home	293	184	108
1-unit, detached	1,390	864	526
Total	**2,147**	**1,337**	**811**

Based on our analysis, the Tierra team estimates Duke Carolina's systemwide market viable units in 2021 to be 1,384,799 and our anticipated first-year participation goal for this program is 3,140. This program will take some time to build awareness and grow participation, particularly due to having to convince homeowners that controllers will not adversely impact their hot water usage, as well as the need to train local contractors how to install the technology and convince them to support customer referrals.

3.5.10 Marketing Plan

The marketing plan will target both customers with electric water heating who are interested in saving money on a TOU rate as well as customers that are in the process of purchasing a new electric water heater. Marketing to both customer groups will require educating customers about the potential energy and bill saving benefits of connected controls as well as emphasizing how un-intrusive program participation is on the average customer's morning routine. Another key will be to form strong partnerships with manufacturers, distributers and installers who can bundle free controllers with water heater replacements, tune-ups, and other smart technology purchases such as smart thermostats. Essential to these efforts is engaging with local contractors and big box retailer associates, who are typically the point of sale for these purchases. This will require a multi-faceted marketing approach, which may include but not be limited to the following:

- Coordinating with manufacturers to conduct contractor trainings that show the benefits of the program for home performance contractors, plumbers, builders, and other trade allies. Work to integrate program messaging into their current marketing initiatives.
- Making it easy for interested customers to learn about and purchase water heating controllers by advertising participating retailers and contractors on Duke's online store, website and social media channels, as well as having participating retailers and contractors advertise the program on their own websites and social media channels.
- Integrating program offerings including both new replacements and retrofit controls into Duke's online marketplace
- Complementary delivery with Duke's existing energy efficiency program offerings, including:
    - The DEP and DEC Residential Smart $aver Programs which already provide residential customers with incentives to purchase high efficiency ENERGY STAR Heat Pump Water Heaters
    - The DEP and DEC Income Qualified Programs (i.e., Neighborhood Energy Saver, and Low-Income Weatherization Programs) which are already providing direct installation of select water heating

measures (e.g., electric water heater wraps/insulation and temperature checks/adjustments) as well as thermostats which may also be upgraded to be rate-enabled

- The DEP and DEC Multi-family Energy Efficiency Programs, which also provide direct install services, are currently used as an alternative delivery channel targeting multi-family apartment complexes and could be leveraged to expand load shifting technologies such as rate-enabled connected water heater controls in the multi-family market.

In addition to manufacturer, distributer and contractor marketing strategies, Duke should consider how to take advantage of other opportunities that may allow for the scaling of these successes in planned replacement scenarios including, but not be limited to the following:

- Targeting neighborhoods where water heaters installed during construction are now approaching the end of their effective useful life
- Targeting outreach to customers who are already enrolled in TOU rates, demand response programs, or those who have purchased smart technologies such as smart thermostats
- Targeting income qualified customers including those that have previously participated in a weatherization program or a Customer Assistance Program (i.e., Energy Neighbor Fund, Share the Warmth Carolinas, and Cooling Assistance Carolinas) and would benefit from a free upgrade that leads to additional bill savings

3.5.11 Measurement & Verification Plan

An evaluation plan should be clearly defined prior to pilot implementation to ensure that all necessary data is collected. These efforts should be coordinated with Duke's current or future evaluators and should include, but not be limited to, the following:

- Conduct kick-off meetings between Duke Energy, implementer, and evaluators to ensure all data needed for evaluation is gathered, will be complete, and will accurately reflect field activities
- Continually solicit customer feedback on program experience through customer surveys and adjust program outreach strategies based on lessons learned
- Conduct impact and process evaluations activities, particularly during the first year to determine program effectiveness both at reducing peak as well as engaging customers and trade allies
- Adjust program quickly as lessons are learned from the impact and process evaluations
- Include onsite measurement and short term/long term data monitoring to establish savings and demand reductions to calibrate engineering estimates

3.5.12 Energy Impacts and Winter Peak Demand Savings

The Tierra team used BEopt to compare the performance of resistance tank heaters to HP tank heaters as well as estimate the peak winter demand savings from a 3-hour water heating control load shifting event. Figure 4 shows that heat pump water heaters use approximately 29% less energy, which translates to 0.2 kW less demand per unit during morning operation. [41]

[41] Proctor Engineering, *Residential HVAC Winter Peak Demand Reduction Opportunities*.

Figure 4. Modelled Electric Water Heater Load Profiles

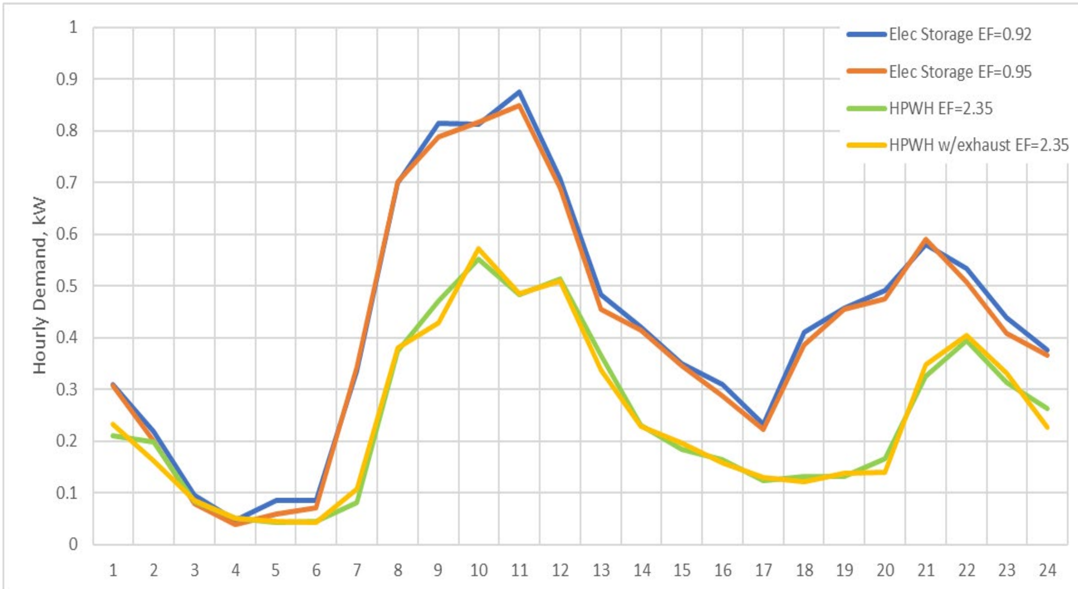


Figure 5 and Figure 6 illustrate the average daily hot water use for a 3-bedroom, 2 bath single family residence, including effects on space heating, during a 3-hour water heating control load shifting event. These figures show that water heaters typically operate in maintenance heat mode (i.e., prior to 6:00 a.m.) and draw about 0.3 kW. Demand increases to about 0.9 kW during morning periods when hot water is gradually being drawn from the tank and replenished by cold water supply. During shift events, no heat is provided to the tank and internal water temperature drops as cold water replenishes the tank during periods when the heating element is not operating (unless a call for hot water needs overrides the control event). Once the shift event ends and the tank begins to heat, demand will typically spike to about 0.87 for tank heaters, as shown in Figure 5 and 0.55 kW for heat pump water heaters as shown in Figure 6.

Figure 5. Modelled Electric Storage Water Heater Peak Load Shed Profile

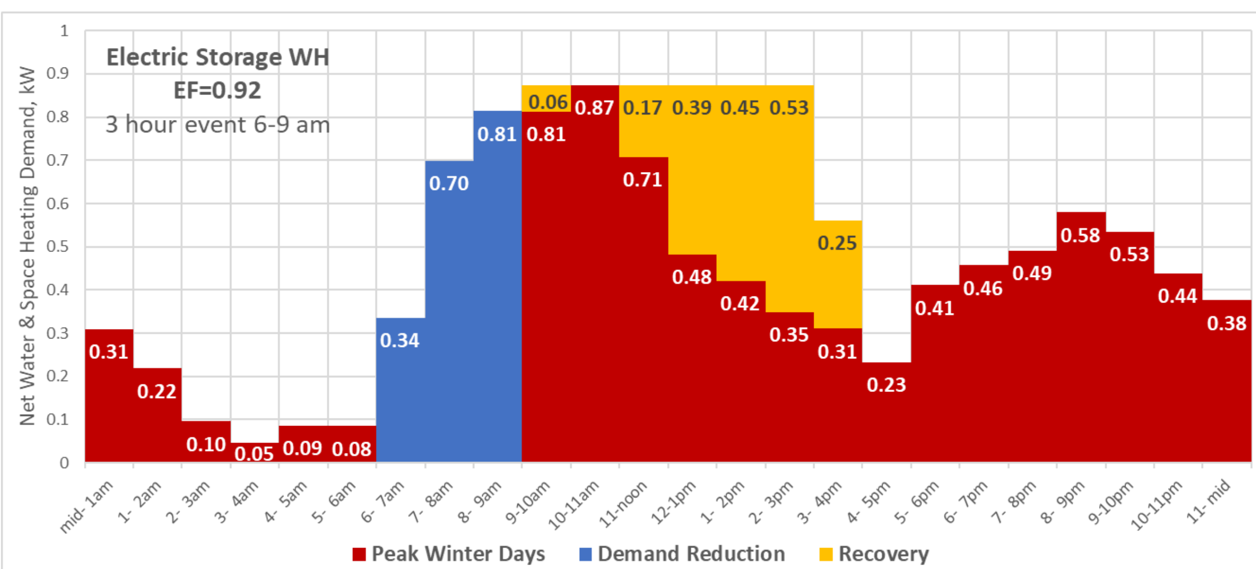
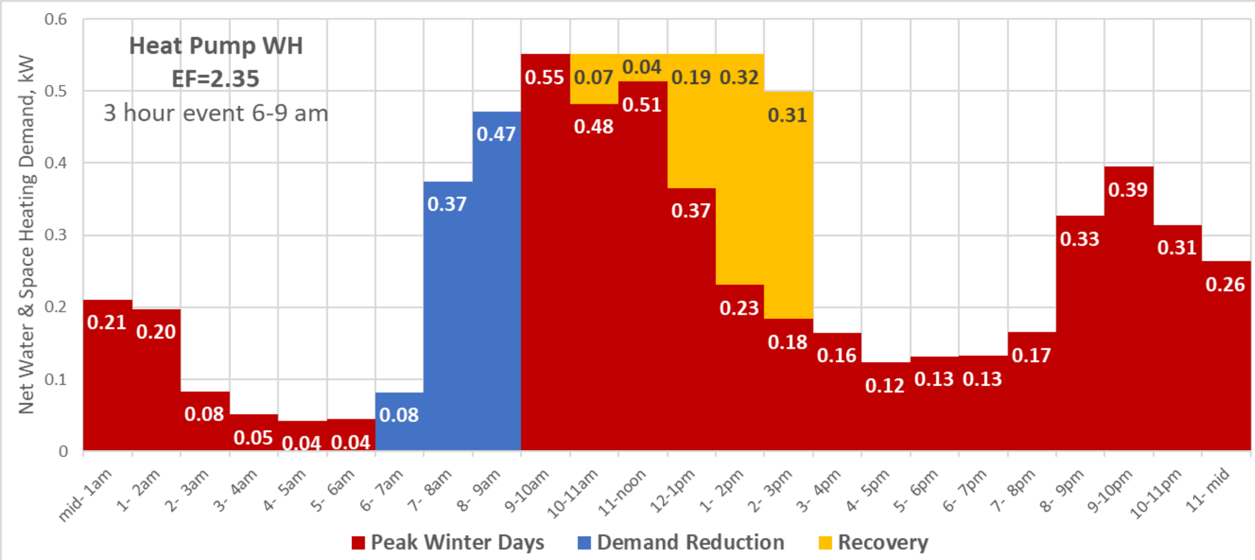


Figure 6. Modelled Heat Pump Water Heater Peak Load Shed Profile



RE-HWH inputs assume no preheat period and a 3-hour shut down beginning at the hour ending at 7:00. Savings are minimal during the first hour but increase as hot water is drawn down over time and normal heat recovery, which increases as hot water is drawn down, is deferred. After the event ends at the hour ending at 9:00, the tank resumes normal recovery heating mode which is extended through the hour ending at 15:00 as the tank recovers temperature on a larger volume of cold water than it would during normal operation because of the 3-hour event shut down. Table 26 shows the hourly kW impacts for single and multifamily dwellings.

Table 26. Hourly RE-HWH kW Impacts for Single and Multifamily Dwellings

Hours Ending	5	6	7	8	9	10	11	12	13	14	15	16
SF	0.00	0.00	0.34	0.70	0.81	-0.06	0.00	-0.17	-0.39	-0.45	-0.53	-0.25
MF	0.00	0.00	0.26	0.53	0.61	-0.05	0.00	-0.13	-0.29	-0.34	-0.40	-0.19

According to the modeling results detailed in the Winter Peak Demand Reduction Potential Assessment, the Connected Water Heater Controls Program could deliver between 2 and 2.2 MW of peak reduction through daily load shifting by winter 2022 and 26.2 MW by 2041. Our modeling assumptions for this program include:

- Costs annual growth of 2%
- Technical Market of 1,384,799 units
- Current installed base of 0
- 3,140 participants in year 1
- Market annual growth of 2%
- Opt-out Rates of 1%
- Connectivity Failures of 6%

3.5.13 Budget

The following estimated program budget is based on the preliminary program design concept as discussed above and the Tierra team's years of experience in program design. Our suggested 1st year program budget assumes:

- 3,140 participants in year 1 with:
  - 75% retrofits
  - 12.5% multi-family direct install
  - 12.5% new construction
- Incentives consisting of:
  - $250/retrofit (free to customer) as a reward for switching to innovative rate plan.
  - $200/ multi-family direct install retrofit.
  - $100/home for builders who install wi-fi connected water heaters in their homes.
- Incremental Measure Cost of $250 for retrofits (including install), $90 for new water heater controllers, and $200 for direct install controller retrofits in the Multi-family sector.

The total program budget will be scaled to the cost of rebates and incentives, which are detailed in Table 27 below.

Table 27. RE-HWHC Program Estimated First Year Rebate and Incentive Costs

Rebate/Incentive	Quantity	Value per Unit	Total Cost (Year 1)
Retrofit	2,355	$250	$588,750
Multi-Family Direct Install	393	$200	$78,500
New Construction	393	$100	$39,250
Total			**$706,500**

Estimated first year program costs, including rebates/incentives and program administration, are presented in Table 28 below.

Table 28. RE-HWHC Program Estimated First Year Budget

Budget Category	Percentage	Year 1 Cost
Rebates and Incentives	49%	$ 706,500
Program Implementation	34%	$ 490,000
Program Marketing and Outreach	8%	$ 120,000
Planning and Administration	8%	$ 120,000
Total	**100%**	**$ 1,436,500**

3.6 EV Workplace / Fleet Charge Management Program ('EV Manage')

Table 29. EV Workplace / Fleet Charge Management Program At-a-Glance

Description	– Commercial EV Workplace/Fleet Charge Management ('EV Manage') is a program designed to proactively manage peak demand from EVs by deploying networked electric vehicle supply equipment (EVSE) that includes managed charging capabilities.
Objectives	– Dynamically control workplace and fleet charging to manage peak demand, especially on the coldest winter mornings when many workplace stations are being used. – Support reliability by shifting EV charging to help flatten system loads and help meet clean energy goals by managing the timing of EV charging to better align with daily solar production. – Realize electric system benefits from managing charging stations based on seasonal and evolving distribution and system level needs through demand response and participant peak management plans.
Measure Life	– 10 Year Effective Useful Life (EUL)
Program Intersection with Winter Peak Needs and IRP Filings	– The load profile of EV charging for light vehicles at workplace charging station locations typically experiences peak demand from 8-10am. This emerging energy demand is coincident with the C&I winter peak profile and Duke's overall system winter peak.
Customer Eligibility / Targets	– Available to qualifying Commercial customers and applicable to both new and existing EV charging stations including: ○ **Fleet Charging.** Duke commercial and industrial customers with vehicle fleets that have a duty-cycle which permits Duke managed off-peak charging. ○ **Workplace Charging**. Businesses who are interested in providing workplace charging stations for their employees. – Eligible charging stations would be required to connect to Duke's cloud based EV management platform and agree to allow stations to be controlled to reduce demand during peak hours. EV charging could be integrated into Duke's DER aggregation platform.
Incentive Design	– $150 enrollment reward for signing-up for the program and signing a 3-year commitment allowing Duke to remotely shift load and co-manage charging speeds during peak periods. This incentive is available to customers with existing or new EVSE. – $150 rebate when installing new EVSE with enhanced features, on-board metering, and communication capabilities needed for managed charging. This rebate is stackable with the previous enrollment award. – Duke may also consider offering an ongoing participation reward of $10 per month paid to the customer to enhance market competition and drive down networking costs. While there are multiple ways to design the participation reward, Duke will consider leveraging utility procurement to offset annual network fees as an incentive for customers to remain enrolled in the program. Industry cost data suggests that annual network contracts cost approximately $17 to $21 per month per charger, but that utility procurements may realize cost savings on the order of $7 per charger per month.
Required Changes to Tariffs or Rates	– This program would not require a change to current tariffs or rates, but it could be combined with EV friendly rate options. ○ Duke could pilot a commercial EV tariff with a super off-peak period to evaluate customers willingness to charge during peak solar production and test mitigating new timer peaks at the local distribution level through active managed charging strategies.
Market Potential and Participation Goals	– We estimate commercial EV charging represents approximately 100 MW of demand in 8-9am timeframe by 2030, which is flexible demand that could easily be shifted to later hours by working with customers to proactively target this load as it emerges.
Marketing Plan	– This program would not require a change to current tariffs or rates, but it could be combined with EV friendly rates. – Focus marketing efforts on public agencies, large private delivery and transportation service companies, and large commercial activity centers that are well positioned to provide charging services to a wide number of employee and/or company vehicles (i.e., high utilization) – The key to engaging outreach will be to identify opportunities for deploying managed charging that are complimentary to the customers' business model. – Marketing efforts for EV load management should be closely aligned and coordinated with Duke's other EV program outreach, including working with trade allies who provide EV charging products and services.
Energy Impacts and Winter Peak Demand Savings	– EV managed charging is an emerging DSM opportunity that should be pursued proactively. We recommend that Duke begin to implement managed charging during winter peak system peak coincidence. Beginning this process now will accomplish the following objectives: ○ Profile the market to help refine estimates of system interaction. This would include tracking development of load impacts from medium and large commercial trucks. ○ Identify third-party service providers for which pilot projects can be developed. ○ Define economic benefits that help drive commercial adoption. ○ Help Duke meet clean energy goals by shifting charging to align with solar production times
Budget	– Estimated first year program costs are expected to total $1,278,750.

3.6.1 Description

The commercial EV Workplace/Fleet Charge Management (EV Manage) Program is designed to proactively address and manage the winter peak demand from EVs by integrating the deployment of networked electric vehicle supply equipment (EVSE) with managed charging. EV Manage may offer workplaces and fleet operators:

1. Incentives to install networked, rather than non-networked, EVSE.
2. Ongoing participation rewards for allowing Duke to remotely control the EVSE to shift load by ramping charging speeds up or down in response to grid needs.
3. An opportunity to participate in other future demand response programs.

The EV Manage program will enable dynamic scheduling of workplace and fleet EV charging to reduce the pace of charging during peak periods and ensure charging occurs during the most optimal times, as well as initiate demand response events when needed. Charging times will be scheduled and managed to best avoid customer, local distribution, and system level peaks while accounting for customers' business needs and charging preferences. This approach will bring the benefits of EVs to participating customers in the most efficient manner for the electric system to maximize benefits for all Duke customers. The program will complement and leverage investments from Duke's pending EV initiatives in the Carolinas, including both the South Carolina and North Carolina Electric Transportation Pilots, while also building on the knowledge gained from Duke's implementation of the Charge Carolinas program as well as the Park and Plug program in Florida.

3.6.2 Objectives

The EV Manage program is a commercial DSM offering designed to integrate active managed charging using load control via smart charging devices with passive managed charging strategies such as incentives rewarding off-peak charging, behavioral demand response, and/or TOU rates. Although current EV load is negligible, managed charging will be a key strategy in addressing the forecasted 100 MW of demand from commercial EV charging at hour 9 by 2030, which is coincident with C&I winter peak. The rationale and objectives for implementing this program include:

- Dynamically manage workplace and fleet charging to limit on-peak charging, with a particular focus on managing charging that is coincident with winter peak
- Deliver managed EV services in coordination with Duke's existing and pending electric transportation programs, which focus on incentivizing the installation of EVSE and collecting utilization characteristics of charging-behavior for a variety of EV types and weight-classes to better understand potential grid and utility impacts
- Realize electric system benefits based on seasonal and evolving distribution and system level needs through EV charging demand response and participant peak management plans
- Begin to evaluate passive managed charging through experimental rate designs and other mechanisms, as recommended in North Carolina Public Staff's proposed order[42]
- Reduce greenhouse-gas emissions and put downward pressure on rates by increasing demand during times when there is abundant renewable generation available

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[42] North Carolina Public Staff Utilities Commission, Public Staff's Proposed Order, Docket No. E-2, Sub 1197 and Docket No. E-7, Sub 1195 - Application for Approval of Proposed Electric Transportation Pilot, February 28, 2020.

- Proactively address the risk of EV adoption causing distribution system impacts that require T&D facility upgrades to meet increased demand
- Enable budget constrained customers to afford EV charging infrastructure more easily, thus empowering customers previously unable to invest in charging infrastructure with the means to do so to provide customer benefits including gasoline savings and lower transportation costs
- Encourage EV adoption across different customer segments within Duke Carolina's service territory.

3.6.3 Measure Life

According to the U.S. Department of Energy, industry stakeholders assume EVSE has at least a 10-year useful life.[43]

3.6.4 Program Intersection with Winter Peak Needs and IRP Filings

As outlined in the winter peak characterization assessment, the load profile of EV charging for light vehicles at workplace charging stations typically experiences peak demand from 8-10am. This emerging energy demand is coincident with Duke's overall winter system peaks, that occur, on average, between the hours ending 8 and 9. Current EV load forecast data provided by Duke estimates approximately 100 MW of coincident peak demand at hour 9 by 2030. Given the aggressive state mandates and technology advancements fueling EV adoption as well as the flexibility of workplace charging load profiles, a proactive approach to managing this emerging load to reduce peak impacts is warranted.

3.6.5 Customer Eligibility / Targets

Available to qualifying Commercial customers and applicable to both new and existing EV charging stations including:

1. **Fleet Charging.** Duke commercial and industrial customers with vehicle fleets that have a duty-cycle which permits Duke managed off-peak charging. A key market will be municipalities, whose jurisdiction and daily miles traveled are easily met with EVs on the market today.
2. **Workplace Charging**. Business customers who are interested in providing workplace charging stations for their employees where charging can be managed to reduce peak demand.

For both fleet and workplace charging, eligible charging stations would be required to connect to Duke's cloud based EV management platform (i.e., Duke's DER aggregation platform) and agree to allow stations to be controlled to reduce demand during peak hours. Qualified program participants may consider requiring customers to enroll in an applicable TOU or future EV-TOU rate.

3.6.6 Incentive Design

This program could offer a $150 rebate for new purchases of qualified networked EVSE that have been preapproved by Duke and it's selected EV management platform provider to have the enhanced features, on-board metering, and communication capabilities needed for managed charging (e.g., Energy Star "Connected Functionality Capable" rated EVSE which can integrate into demand response programs). Duke may consider using upstream and/or midstream incentives to manufacturers and/or retailers to lower the incremental material cost of qualified networked chargers.

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[43]US Department of Energy *Costs Associated with Non-Residential Electric Vehicle Supply Equipment Factors to consider in the implementation of electric vehicle charging stations*, November 2015. Page 21. https://afdc.energy.gov/files/ue/publication/evse_cost_report_2015.pdf

In exchange for allowing Duke to remotely shift load and co-manage the charging speeds of enrolled EVSE, customers may receive a $150 enrollment reward for signing-up for the program and signing a 3-year commitment. This incentive would be layered with the $150 rebate for Duke qualified purchases of new networked EVSE or be a received as a stand-alone incentive for customers with existing equipment who are willing to allow Duke to remotely shift load and co-manage their charging stations for a minimum of 3-years. Duke may also consider offering an ongoing participation credit of $10 per month paid to the customer to enhance market competition and drive down networking costs. While there are multiple ways to design the participation reward, Duke will consider leveraging utility procurement to offset annual network fees as an incentive for customers to remain enrolled in the program. Industry cost data suggests that annual network contracts cost approximately $17 to $21 per month per charger, but that utility procurements may realize cost savings on the order of $7 per charger per month.[44] These incentives will be available to customers with existing or new connected EVSE.

3.6.7 Required Changes to Tariffs or Rates

As EV load grows over time, EV specific rates and EV load management programs will be critical to influencing commercial drivers to shift their load. Public Staff stated in their Proposed Order on the pending Electric Transportation Pilot Program that "a robust pilot project should evaluate passive managed charging through experimental rate designs and other mechanisms".[45] Accordingly, Duke could pair this program's active managed charging via networked chargers with pilot rate design to better understand the impacts on charging behavior. In parallel with this program, Duke may consider a study on commercial EV rates tailored to customer and grid needs. As part of this study, Duke may consider the opportunity to pilot a Commercial EV tariff with a super off-peak period, such as after the morning winter peak and before lunch. This would enable an evaluation of customers willingness to charge during peak solar production and test mitigating new timer peaks at the local distribution level through the active managed charging strategies proposed in this program.

3.6.8 Implementation and Operation

For implementation of the networked EVSE component of this program, Duke should directly oversee the deployment of charging infrastructure, and deliver this element of the program with assistance from its existing EV Implementation and Evaluation contractor partners from the previous Charge Carolinas and the pending Electric Transportation Pilot Program. The EV Manage program will function independently of the proposed Electric Transportation Pilot Program in North Carolina but it is anticipated that if both programs are approved, they will be implemented in parallel to leverage overlapping program delivery and evaluation infrastructure. Duke should work with these EV program implementation contractors and through existing communications channels to promote and implement the program outreach. In addition, Duke will partner with manufacturers and local retailers to actively promote the program and make networked EVSE available through Duke's existing online stores.

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[44] Chris Nelder and Emily Rogers, Reducing EV Charging Infrastructure Costs, Rocky Mountain Institute, 2019, https://rmi.org/ev-charging-costs.

[45] North Carolina Public Staff Utilities Commission, Public Staff's Proposed Order, Docket No. E-2, Sub 1197 and Docket No. E-7, Sub 1195 - Application for Approval of Proposed Electric Transportation Pilot, February 28, 2020. Page 9.

For the direct load control element of this program, Duke should leverage the DER aggregation platform to implement the program, which should include:

- Utilizing managed charging to facilitate load shifting and charge rate throttling in response to local system conditions and particularly around morning winter peaks
- Aggregating EV load as a demand response resource that can be combined and aggregated with other DERs to provide grid resources during winter and summer critical peak periods
- Matching EV charging with renewables production to maximize the absorption of excess renewable generation (for example, by delaying morning charging of Workplace charging stations to occur later in the morning after the peak and aligned with when solar production begins to ramp up in the morning)
- Access to EV monitoring and data management systems capable of providing custom analysis and device level charging behavior insights
- Enrollment infrastructure and processing automation that has been used successfully by other utility managed charging programs

Duke should also work to minimize charging disruptions by having the selected DERMS vendor develop an intelligent platform that provides predictive capabilities to forecast load estimates by time and location. Duke and the selected DERMS vendor can work with participating customers to establish managed charging schedules. These charging schedules will be designed to:

- Address consumer preferences for different charging solution features and levels of interaction based on their business needs, including the opportunity for participants to opt-out of or override a managed charging event
- Encourage charging to occur after the morning winter peak through mid-afternoon, when EV charging can take advantage of excess solar energy production
- Define a typical slow charging rate from 6am-9:30am, which is coincident with winter peak

3.6.9 Market Potential and Participation Goals

Duke forecasts estimate that commercial EV charging represents approximately 100 MW of demand in 8-9am timeframe by 2030. This is flexible demand that could easily be shifted to later hours by working with customers to proactively target this load as it emerges.

Within the scope of this study, we did not have the requisite data (including saturation of electric vehicles in the commercial and industrial market) to estimate the market potential and participation of managed workplace and fleet charging. Due to this data gap and project scope/timeline constraints, it was omitted from our detailed modeling efforts.

Regardless, we believe EV managed charging represents a long-term DSM opportunity that should be the focus of future studies and recommend that Duke begin defining how managed charging will operate during system winter peak coincidence. Beginning this process now will accomplish the following objectives:

- Profile the market to help refine estimates of system interaction, which would include tracking development of load impacts from medium and large commercial trucks
- Identify third-party service providers for which pilot projects can be developed
- Define economic benefits that help drive commercial adoption to help accelerate revenue growth

3.6.10 Marketing Plan

The EV Manage program’s marketing, education and outreach should initially focus on public agencies which often have both large fleets and workplaces, large private delivery and transportation service companies, large commercial activity centers that are well positioned to provide charging services to a wide number of employee and/or company vehicles, as well as medium to large commercial customers and fleets located in solar-saturated circuits. Additionally, Duke can identify and conduct targeted outreach to smaller businesses located in charging deserts, to ensure access to charging is spread thoroughly throughout the service territory. Large organizations and charging deserts that overlap with underserved and rural communities can be prioritized as needed to fill gaps in charging services.

The EV Manage Program marketing and communications efforts should be integrated with other DSM programs, messages, and communications channels. Duke can work closely with its Key Account Managers to inform commercial customers and provide education materials to potential program participants. The key to engaging outreach will be to identify opportunities to install EVSE that align with and are beneficial to the customers' business model. This outreach will begin primarily through outreach from, and collaboration with, known community assets and stakeholders. This will include multiple communication modes and educational outreach that focuses on defining and promoting the key benefits of implementing networked EVSE to property owners. Commercial demand response opportunities available for EVSE will also be co-marketed. Customer education on the cost saving associated with shifting charging to off-peak, demand response programs, and time-of-use (TOU) tariff options will also be conducted as part of this program's outreach activities.

3.6.11 Measurement & Verification Plan

An evaluation plan should be clearly defined prior to pilot implementation to ensure that all necessary data is collected. These efforts should be coordinated with Duke's current or future evaluators and should include, but not be limited to, the following:

- Coordinate a kick-off meeting between Duke Energy, implementer, and evaluators to ensure all data needed for evaluation is gathered, will be complete, and will accurately reflect field activities
- Continually solicit customer feedback on program through customer surveys and adjust implementation activities based on lessons learned
- Conduct impact and process evaluation activities frequently during the first year to determine program effectiveness both at reducing peak as well as engaging customers and trade allies
- Adjust program quickly as lessons are learned from the impact and process evaluations
- Include onsite measurement and short term/long term monitoring to establish savings and demand reduction as well as engineering estimates
- Use customer and contractor surveys to help refine program outreach and delivery mechanisms

3.6.12 Energy Impacts and Winter Peak Demand Savings

In considering EV managed charging, we reviewed available workplace charging load forecasts and resulting load shapes. Figure 7 compares C&I and commercial workplace charging winter peak demand profiles showing that workplace charging peak is at hours ending 9:00 and 10:00 and is coincident with C&I peak occurring between hours ending 9:00 and 11:00. Figure 8 provides our analysis of EV load forecast data provided by Duke, showing approximately 100 MW of demand at hour 9 by 2030.

Figure 7. Comparison of C&I and Commercial Workplace Charging Winter Peak Demand Profiles

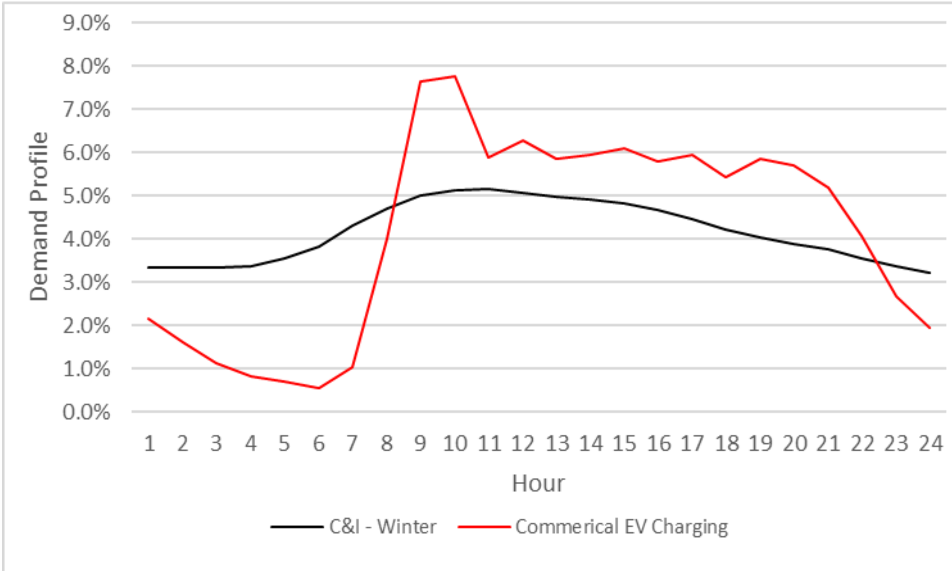
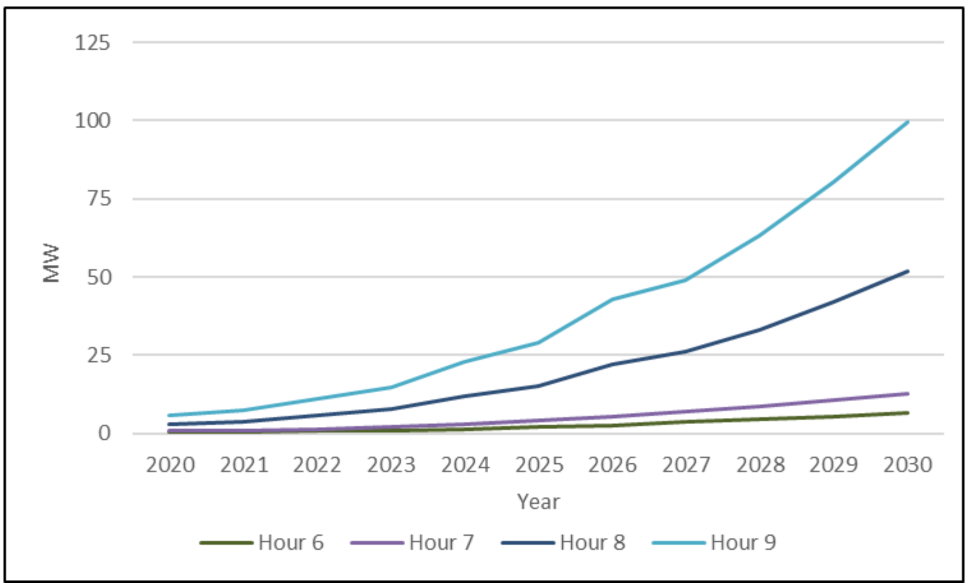


Figure 8. EV Charging Load Forecast by Morning Hour



3.6.13 Budget

The following estimated program budget is based on the preliminary program design concept as discussed above and the Tierra team's years of experience in program design. Our suggested 1st year program budget assumes:

- This program will occur later than other programs described in this report due to the need to perform an EV specific saturation and market potential study to fill existing data gaps (see section 3.6.9 for more details).
  - Duke Carolinas will have higher level 2 workplace and fleet charging saturation by the time this program launches.
  - Final program participation, incentives and budgets will be dependent on results of future market studies and EM&V of existing and approved EV programs in Duke's territory.
- 5,500 chargers enrolled in year 1, with:

- 85% new networked EVSE
- 15% existing networked EVSE

- Incentives consisting of:
  - $150/new qualified networked EVSE
  - $150/enrollment reward (both new and existing networked EVSE)
  - $10/month participation reward paid to the customer paid to the customer to enhance market competition and drive down networking costs.
- Incremental Measure Cost of a level 2 networked EVSE can be as much as $500 although the additional technology typically costs less than $50.[46]

The total program budget will be scaled to the cost of rebates and incentives, which are detailed in Table 30 below.

Table 30. EV Manage Program Estimated First Year Rebate and Incentive Costs

Rebate/Incentive	Quantity	Value per Unit	Total Cost (Year 1)
Enrollment Reward	5,500	$150	$825,000
New Networked EVSE	825	$150	$123,750
Participation Reward	5,500	$120	$660,000
Total			**$1,608,750**

Estimated first year program costs, including rebates/incentives and program administration, are presented in Table 31 below.

Table 31. EV Manage Program Estimated First Year Budget

Budget Category	Percentage	Year 1 Cost
Rebates and Incentives	53%	$1,608,750
Program Implementation	37%	$1,120,000
Program Marketing and Outreach	4%	$ 125,000
Planning and Administration	6%	$ 170,000
Total	**100%**	**$ 3,023,750**

[46] Chris Nelder and Emily Rogers, Reducing EV Charging Infrastructure Costs, Rocky Mountain Institute, 2019. Page 19.

3.7 Automated Demand Response ('ADR')

Table 32. ADR Program At-a-Glance

Description	– The ADR program will provide incentives and technical assistance to install and/or program equipment at medium to large nonresidential customers' facilities. This equipment will enable Duke to directly curtail electrical load during a DR event without participant intervention, with the objective of maximizing the reliability and consistency of available kW capacity. – Business customers will be able to choose from a menu of equipment incentives that enable the following DR strategies: global temperature adjustment, HVAC equipment cycling, light shutoff or dimming, process adjustments, and other HVAC and lighting adjustments.
Objectives	– Fill gaps in the current C&I DSM offering and diversify the DSM resource mix and improve reliability. – Reduce opt-outs by expanding the DSM value proposition and reduce participant attrition – Leverage emerging Duke data infrastructure to manage DSM operation costs – Increase DSM cost recovery – Expand both summer and winter demand response capacity and provide a pathway for emerging technology adoption
Measure Life	– The Winter Peak Demand Reduction Potential Assessment study utilized a measure life of 10 years for the ADR program. This is subject to change based on the final measures offered to program participants.
Program Intersection with Winter Peak Needs and IRP Filings	– As discussed throughout the Winter Peak Analysis Study's Large C&I Capacity section, Duke's DSM solution for large C&I customers relies mostly on the use of customer sited backup generation and process interruptions which offer limited potential. – The Winter Peak Analysis study recommended that Duke consider further researching the potential for an ADR program to encourage C&I customers to opt back into the EE rider and adopt new time variant pricing options.
Customer Eligibility / Targets	– The primary target markets for ADR will consist of medium and Large C&I customers, particularly those already enrolled in a C&I eligible time variant pricing option and that have not opted out of the DSM Rider. They should also be interested in more flexible options for participating in demand response events.
Incentive Design	– The rate design structure for ADR program may consist of two incentives: ○ An equipment incentive of up to $200/kW for customers to install and/or program the necessary equipment at the customer's facilities to replace labor-intensive manual and semi-ADR with a fully automated DR system. ○ A capacity credit that rewards customers $3.5/kW they reduce on critical event days. – Duke may call up to 12 critical event days or approximately 36 hours each year through this program.
Required Changes to Tariffs or Rates	– Duke will need to conduct further research into which specific rates and technologies should be combined and offered to customers through this program to produce the greatest kW demand reduction potential.
Market Potential and Participation Goals	– We reviewed available CBECS data to estimate the number of commercial buildings in Duke's territory as well as the average square footage by segment. Based on our analysis, the Tierra team estimates Duke Carolina's systemwide market viable units in the first year to be 30,966 and our anticipated first-year participation goal for this program is .5% penetration or 155 customers.
Marketing Plan	– An integrated marketing plan should be developed to target key C&I segments and customers. It should include: ○ Run in-app promotions with participating thermostat manufacturers who can promote the program direct to smart thermostats in Duke's territory ○ Create program landing pages on Duke's website and linked to thermostat manufacturers ○ Integrate this program into existing program delivery channels for other existing C&I programs ○ Scale the program in conjunction with the introduction of new innovative rates and tariffs that can be paired ○ Use Duke's existing relationships with key segments and trade allies. ○ Utilize Duke's in-house customer information channels (e.g., emails, newsletters, bill inserts) ○ Promote the program on social media
Energy Impacts and Winter Peak Demand Savings	– Assuming a steady .5 percentage point increase in penetration each year, Table 26 shows the project team's estimated ADR program impact in the first year of the program will be 3.5 MW of peak reduction from 155 customers across various commercial segments, growing to 35.3 MW from 1,548 customers in 2031.
Budget	– Estimated first year program costs are expected to total $3,186,125.

3.7.1 Description

The ADR program will provide incentives and technical assistance to install and/or program equipment at medium to large nonresidential customers' facilities. This equipment will enable Duke to directly curtail electrical load during a DR event without participant intervention, with the objective of maximizing the reliability and consistency of available kW capacity. The technology solution should consist of an open, interoperable industry standard control as well as communications technologies designed to work with both common energy management control systems and individual end-use devices. The technologies include a communications infrastructure via a computer server that can send DR signals to participant sites where load reductions are automatically implemented through building control systems. ADR is a fully automated DR system using Client/Server architecture and is intended to replace labor-intensive manual and semi-ADR. [47] In general, business customers will be able to choose from a menu of equipment incentives that enable the following DR strategies:

- Global temperature adjustment: Existing energy management control systems (EMCS) can be adjusted to receive a DR event signal. Once that signal is received, the EMCS raises the setpoint temperature established by a customer (usually in the range of two to eight degrees) for a period.
- HVAC equipment cycling: For buildings with multiple packaged HVAC systems, select units can be configured to receive a DR event signal. Once that signal is received, compressor units shut off for a subset of the building's systems during an acceptable period. Additional signals are then sent to restart those units and shut off other units.
- Other HVAC adjustments: Other HVAC shed strategies include decrease in duct pressures, auxiliary fan shutoff, pre-cooling, valve limits and boiler lockouts.
- Light shutoff or dimming: Various lighting circuits can be wired to receive a DR event signal. When signaled, these loads are tripped or dimmed for the entire duration of the DR event. Typically, these are for lighting applications in common areas with sufficient natural light or for task applications that could accommodate full shutoff given the proximity of other lighting in the area.
- Other lighting and miscellaneous adjustments: Other shed strategies that may be employed include bi-level lighting switches and motor/pump shutoff.
- Process adjustments: Given the varying nature of industrial processes, the strategy for each customer should be tailored to their process. A common ADR strategy is modifying ancillary processes where there is sufficient storage capability such that the customer can accommodate complete equipment shutdowns during DR events and catch-up production later in the day or the following day.

3.7.2 Objectives

The ADR program is an integrated DSM offering that will install and/or program equipment capable of delivering load shifting and demand response capacity savings that help address the current and future needs of Duke's winter peaking electric grid.

The objectives for implementing this program include:

- Fill gaps in the current C&I DSM offering
- Diversify the DSM resource mix and improve reliability

[47] The technology and communications infrastructure used in ADR originated from an initial conceptual design developed in 2002 at Lawrence Berkeley National Laboratory (LBNL).

- Reduce opt-outs by expanding the DSM value proposition
- Reduce participant attrition
- Leverage emerging Duke data infrastructure to manage DSM operation costs
- Increase DSM cost recovery
- Expand both summer and winter demand response capacity
- Provide a pathway for emerging technology adoption

3.7.3 Measure Life

The Winter Peak Demand Reduction Potential Assessment study utilized a measure life of 10 years for the ADR program. This is subject to change based on the final measures offered to program participants.

3.7.4 Program Intersection with Winter Peak Needs

As discussed throughout the Winter Peak Analysis Study's Large C&I Capacity section, Duke's DSM solution for large C&I customers relies mostly on the use of customer sited backup generation and process interruptions which suffer from the following shortcomings:

- The backup generation market is limited and may not be growing as industrial loads decline, and potential that may exist is likely to have been recruited through the legacy and EE rider programs in operation over the past decade. This potential is also at risk because it is subject to regulatory constraints outside of Duke's control.
- DSM capacity related to production interruptions and responses from one event to the next are variable because it is unlikely to respond during multiple concurrent days, such as a polar vortex. In addition, this resource is generally restricted to use only in grid emergencies and our impression is that these are called infrequently.

The Winter Peak Analysis study recommended that Duke consider further researching the potential for an ADR program to encourage C&I customers to opt back into the EE rider and adopt new time variant pricing options.

3.7.5 Customer Eligibility/Targets

The primary target markets for ADR will consist of medium and Large C&I customers, particularly those already enrolled in a C&I eligible time variant pricing option and that have not opted out of the DSM Rider. They should also be interested in more flexible options for participating in demand response events, but require new equipment or programming to participate.

The ADR program requires that customers:

- Have a standard AMI meter in place (Duke may install and certify an eligible meter upon customer request to participate)
- Be willing to enroll in eligible demand response events through an applicable C&I demand response program such as the PTR program described previously in this report.
- Agree to have an OpenADR 2.0 A or B certified virtual end node (VEN) on site that pulls the automated DR event signal directly from a utility or aggregator.

3.7.6 Incentive Design

The rate design structure for ADR program will consist of two incentives:

- An equipment incentive of up to $200/kW for customers to install and/or program the necessary equipment at the customer's facilities to replace labor-intensive manual and semi-ADR with a fully automated DR system.
- A capacity credit that rewards customers $3.5/kW they reduce on critical event days.

As designed, Duke may call up to 12 critical event days or approximately 36 hours each year through this program. The number of critical event days permitted annually may be exceeded in the event of a system emergency that is expected to place Duke's ability to provide reliable service to customers at risk. Events may be called in any month, but for no more than 4 consecutive days, and will be scheduled as follows:

- 6:00 a.m. to 10:00 a.m. plus 6:00 p.m. to 9:00 p.m. Monday through Friday, excluding holidays during the winter season.
- 2:00 p.m. to 8:00 p.m. Monday through Friday, excluding holidays during the summer season.

Duke should use its best efforts to notify customers by 4:00 p.m. on the prior day for critical event days, however, notification of critical event days can occur at any time, but no later than one hour prior to the on-peak period. The customer will receive a phone message, e-mail, or text message notification of upcoming event days and is responsible to watch for this message. Once noticed, a CPP event will not be cancelled.

3.7.7 Required Changes to Tariffs or Rates

Duke will need to conduct further research into which specific rates and technologies should be combined and offered to customers through this program to produce the greatest kW demand reduction potential.

3.7.8 Implementation and Operation

Duke should develop, market and administer the ADR program with assistance from an experienced ADR aggregation platform partner to fine-tune the program strategy, implementation, and operations including the process for enrolling customers, deploying and connecting large C&I customer systems to the platform, tracking participation, and paying incentives. Key operational activities include project management, call center operations, daily website updates, and deployment of customer notifications. Duke should leverage its existing infrastructure, such as that used in the Flex Savings Options Pilot, for notifying customers of critical event days. Prior to rolling out this program, Duke should assess the team responsible for handling notifications and customer outreach to ensure that there are adequate resources to monitor the accuracy and performance of vendor systems in real time as well as support increased call volume resulting from the price change and installation issues related to new smart thermostats and meters. The following additional steps should also be undertaken prior to program launch:

- Work with HVAC and lighting OEMs and local contractors to confirm the characteristics of qualified equipment installed in the Duke Carolinas service territory.
- Work with local installers to inform them about the program, encourage them to promote the program to their customers, and train them how to enroll customers.
- Develop training, QA/QC, and commissioning programs.

3.7.9 Market Potential and Participation Goals

In considering an ADR program, the Tierra team reviewed available CBECS data to estimate the number of commercial buildings in Duke's territory as well as the average square footage by segment. This enabled us to estimate market potential for the ADR program by segment, as shown in Table 33. Based on our analysis, the Tierra team estimates Duke Carolina's systemwide market viable units in the first year to be

30,966 and our anticipated first-year participation goal for this program is .5% penetration or 155 customers.

Table 33. ADR Market Potential by Segment

Segment	Buildings				Viable Market		MW Shed				
	DEC	DEP	Duke	Ave Bldg. Sq Ft	% Viable	Buildings	Technical	Coincident	Sq. Ft	Tier	KW
Education	9,450	5,964	15,414	32,644	40%	6,166	280	252	201,266,072	4	45.4
Food sales	4,345	2,742	7,087	4,700	5%	354	1	1	1,665,406	1	3.3
Food service	8,472	5,347	13,819	5,077	5%	691	2	2	3,507,983	1	3.3
Health care Inpatient	155	98	253	283,500	40%	101	5	4	28,701,676	4	45.4
Health care Outpatient	2,281	1,440	3,721	12,238	10%	372	3	3	4,553,291	2	7.6
Lodging	3,584	2,262	5,847	36,879	40%	2,339	106	95	86,246,764	4	45.4
Mercantile Retail	9,993	6,307	16,300	11,435	25%	4,075	31	28	46,595,930	2	7.6
Mercantile Enclosed Mall	5,540	3,496	9,036	33,216	40%	3,614	164	148	120,050,960	4	45.4
Office	21,506	13,574	35,080	16,076	10%	3,508	27	24	56,393,478	2	7.6
Public assembly	4,888	3,085	7,973	20,089	25%	1,993	23	21	40,040,609	3	11.5
Public order and safety	1,700	1,073	2,773	54,753	40%	1,109	50	45	60,734,163	4	45.4
Religious worship	8,689	5,484	14,174	10,713	10%	1,417	11	10	15,183,541	2	7.6
Service	10,862	6,855	17,717	7,410	5%	886	3	3	6,564,180	1	3.3
Warehouse and storage	19,225	12,134	31,359	16,000	10%	3,136	24	22	50,174,781	2	7.6
Other	1,847	1,165	3,012	33,412	40%	1,205	55	49	40,253,214	4	45.4
Total	**112,537**	**71,026**	**183,563**	**578,140**	**17%**	**30,966**	**784**	**705**	**761,932,049**		

3.7.10 Marketing Plan

An integrated marketing plan should be developed to target key C&I segments and customers. It should include:

- Run in-app promotions with participating thermostat manufacturers who can promote the program direct to smart thermostats in Duke's territory
- Create program landing pages on Duke's website and linked to thermostat manufacturers
- Integrate this program into existing program delivery channels for other existing C&I programs
- Scale the program in conjunction with the introduction of new innovative rates and tariffs that can be paired
- Use Duke's existing relationships with key segments and trade allies.
- Utilize Duke's in-house customer information channels (e.g., emails, newsletters, bill inserts)
- Promote the program on social media

3.7.11 Measurement & Verification Plan

A detailed Measurement & Verification (M&V) Plan should be developed for this program, which will require coordination between Duke Energy and Duke's evaluation contractor. The M&V plan should be designed to ensure that the program meets utility, customer, and regulatory objectives and key performance indicators.

Important M&V areas of focus for this program will include:

- Process evaluation to determine opportunities to streamline and improve program processes and improve customer experience/participant satisfaction, including metrics such as:
  - Frequency of event opt outs and overrides
  - Post enrollment, post event and post season surveys
- Impact evaluation to determine the program's energy impacts including:
  - Description of baseline methodology
  - Measuring hourly peak kW demand impacts from dispatched DR events
  - Complete analysis of load shape impacts compared to baseline before, during and after DR events
  - Impacts disaggregated by various criteria including dwelling type, control type, etc.
  - Developing better forecasting of program impacts based on specific weather conditions and DR event parameters

3.7.12 Energy Impacts and Winter Peak Demand

Assuming a steady .5 percentage point increase in penetration each year, Table 34 shows the project team's estimated ADR program impact in the first year of the program will be 3.5 MW of peak reduction from 155 customers across various commercial segments, growing to 35.3 MW from 1,548 customers in 2031.

Table 34. ADR Program MW Impacts

Year	Penetration	Customers	Coincident MW Shed
2022	0.50%	155	3.5
2023	1.00%	310	7.1
2024	1.50%	464	10.6
2025	2.00%	619	14.1
2026	2.50%	774	17.6
2027	3.00%	929	21.2
2028	3.50%	1,084	24.7
2029	4.00%	1,239	28.2
2030	4.50%	1,393	31.7
2031	5.00%	1,548	35.3

3.7.13 Budget

The following estimated program budget is based on the preliminary program design concept as discussed above and the Tierra team's years of experience in program design. Our suggested 1st year program budget assumes:

- 155 Participants enrolled in year 1, primarily consisting of the largest customers with sites greater than 30,000 square feet.
- Incentives consisting of:
  - $200/kW equipment incentive
  - $3.5/kW monthly capacity credit
- An average per site winter KW yield for ventilation and lighting of 45.4 kW for sites greater than 30,000 square feet. This results in:
  - An average upfront equipment incentive of $9,070
  - An average annual capacity credit of $1,905

The total program budget will be scaled to the cost of rebates and incentives, which are detailed in Table 35 below.

Table 35. ADR Program Estimated First Year Rebate and Incentive Costs

Rebate/Incentive	Quantity	Value per Unit	Total Cost (Year 1)
Avg Customer Equipment Incentive	155	$9,070	$1,405,850
Avg Annual Capacity Credit	155	$1,905	$295,275
Total			**$1,701,125**

Estimated first year program costs, including rebates/incentives and program administration, are presented in Table 36 below.

Table 36. ADR Program Estimated First Year Budget

Budget Category	Percentage	Year 1 Cost
Rebates and Incentives	53%	$1,701,125
Program Implementation	37%	$1,190,000
Program Marketing and Outreach	4%	$125,000
Planning and Administration	5%	$170,000
Total	**100%**	**$3,186,125**

4. Recommendations and Next Steps

In this section, the Tierra team provides a list of findings and recommendations that came out of the research and analysis activities described in this report, and also findings and recommendations from research conducted in the Winter Peak Analysis and Solution Set study[48] and the Winter Peak Demand Reduction Potential Assessment study[49]. Note that not all findings have an associated recommendation.

Finding #1: Based on the results of the winter peak demand reduction potential assessment, there is an apparent 1,273 MW in 2041 **(Mid Scenario –DEC and DEP combined) of winter season DSM potential by 2041** representing ~4.0% of peak. **Most of this potential can be achieved via the residential sector using new rates and expanding mechanical solutions.**

> **Recommendation:** Residential sector programs are key to achieve significant winter demand reduction potentials. As a first step, smart thermostat load shifting/demand response programs and rate structures should be deployed. For instance, a winter BYOT program can likely be implemented as the lowest-hanging fruit option, by adapting the existing summer peak BYOT program to include winter peak events. Following that, TOU and TOU+CPP rate designs could be implemented, pending positive results from the Flex Savings Options Pilot conclusions. These rate designs can then be paired with rate enabled connected technology programs like smart thermostats and connected water heating controls. At the same time, Duke should start pilots to learn more about effective demand management with emerging technologies such as electric vehicles and battery storage.

Finding #2: Changes to PTR incentive levels have very little impact on medium and large C&I customer potentials. For these customers, Duke does not need to provide higher program incentives to drive adoption as the level of incentive in the low scenario is sufficient to capture 91% of the maximum potential (scenario 3).

> **Recommendation:** Within commercial and industrial segments, start by implementing a PTR rate structure which shows higher potential to achieve demand reduction than adding other new DSM programs. As a second step, add Automated Demand Response solutions which could be combined with PTR to enhance current DSM programs.

Finding #3: The modeled solution set reduces peak hour demand and does not shift the winter peak to another hour. This is because the current DEC/DEP system load shapes have relatively steep winter peaks, which makes programs like demand response, storage and load shifting particularly effective opportunities to address Duke's winter peak resource needs.

Finding #4: Table 37 and Table 38 show a high-level comparison between the Nexant Market Potential Studies' (MPS) base and enhanced scenario program potential with the Tierra Demand Reduction Potential Assessment's 'Scenario 3' potential. For 2035, the DSM forecast capacity of 1,924 MW is defined for DEP and DEC in the tables below based on the winter peak study mid case and MPS enhanced case. The winter

[48] Winter Peak Analysis and Solution Set. Tierra Resource Consultants. December 2020

[49] Winter Peak Demand Reduction Potential Assessment. Tierra Resource Consultants. December 2020

peak study mid scenario forecast potential of 1,185 MW is mostly incremental to the MPS and 67% of the winter peak study potential is associated with rates. For context, the Base Case with Carbon Policy discussion in the 2020 IRP estimate Cumulative Capacity with DSM in in 2035 are 22,878 for DEC and 19,116 for DEP. Additionally, the total winter resource gap in 2035 from the 2020 IRP Base Case with Carbon Policy load resource policy analysis is 7,058 MW, with a forecasted shortfall for DEP of 3,835 MW and 3,223 MW for DEC. DSM capacity is based on the MPS study and does not include forecasted Winter Peak Targeted DSM plan impacts.[50]

When comparing studies, it is important to note that the MPS looked at only mechanical technology solutions[51], while the winter peak study looked at opportunities to combine both rate design and EE/DSM technologies to manage winter peak. In addition, the Winter Peak Study did not set out to be a comprehensive look at all potential but specifically focused on targeted opportunities and savings load shapes to best address winter peak needs. In total we found lower savings from mechanical solutions than the market potential study[52] but found mostly incremental potential from the combination of rates and technologies. In the context of the IRP, note that the potential savings from new rate options would be captured in Duke's load forecast, not in EE/DSM potential, since it would be a change to load in response to these rates. Although our study was not timely to be directly included in Duke's current IRP, in total our findings align within the 'high EE/DSM' scenario in the IRP and help bolster this high scenario and provide higher confidence that this level of savings could be achievable. Realizing these opportunities will require a process of regulatory approvals for new rates/tariffs and programs; and these forecasted estimates will need to be calibrated against actual M&V data as new rates, programs, and technology options are deployed. Nonetheless, the study has identified significant winter peak potential opportunities to move forward with, including the winter peak focused smart thermostat DR program that was recently filed.

[50] 2020 DEP and DEC, North Carolina and South Carolina Integrated Resource Plans.

[51] Nexant's MPS also included contractual C&I programs which were not part of the Demand Reduction Potential Assessment. These programs included interruptible rates; guaranteed load drop and emergency load management; and load control programs that incentivize economic load response.

[52] Based on our review of the Nexant MPS, most mechanical solutions found in the Demand Reduction Potential Assessment are not found in the MPS and thus represent mostly incremental potential. The MPS technologies where there is potentially some overlap are smart thermostats, winter HVAC energy efficiency measures, Auto DSM for process loads, and battery storage. For smart thermostats, we believe the MPS captured demand savings from a limited number of customer accounts who purchased a thermostat from the Duke online store or participated in EnergyWise summertime demand response. This means that only a portion of the BYOT program is incremental, particularly from the winter demand response and increased participation from expanded incentives, and the entire RET program is incremental because rate-enabled thermostats were not included in the MPS. For the others, we believe our potential is mostly incremental because it is based on operationalizing a more specific set of high value technologies and new rates.

Table 37. Achievable Potential Comparison - Mid Scenario and MPS Enhanced Scenario (DEC)

Sector	Source	DEC 2035		
		WInter Peak Study (Mid Scenario)	MPS (Enhanced Case)	Total
Potential Total (MW)		**713**	**454**	**1167**
C&I	Rates	105	64	217
	Mechanical	47		
Residential	Rates	384	390	950
	Mechanical	177		

Table 38. Achievable Potential Comparison - Mix Scenario and MPS Enhanced Scenario (DEP)

Sector	Source	DEP 2035		
		WInter Peak Study (Mid Scenario)	MPS (Enhanced Case)	Total
Potential Total (MW)		**472**	**286**	**757**
C&I	Rates	46	5	84
	Mechanical	34		
Residential	Rates	254	281	673
	Mechanical	138		

Finding #5: As discussed in Winter Peak Analysis and Solution Set study, winter peaks are primarily driven by residential electric space heating loads and these loads can be difficult to predict because of the way residential heat pumps work during their heating cycle. Heat pumps provide both space cooling and space heating and the condensers work the same in either the heating or cooling mode. However, most heat pumps systems also have supplemental resistance heaters that provide additional heating capacity when a dwelling requires more heat than the condenser can provide. This supplemental resistance heating can increase total heat pump demand by a factor of 3 (e.g., increase from 4 kW to 12 kW for a single home). In short, the same home equipped with a heat pump might have three times the HVAC load in winter as it does during the summer, and while this disparity makes winter peaks harder to predict it is also shorter in duration than summer peak and can be effectively controlled through programmatic solutions

Recommendation: The research completed by the team leveraged various studies, such as Duke's 2019 Residential Appliance Saturation Survey which provided valuable market information, but none of these resources provided significant insights into supplemental resistance heaters. It's recommended that additional market research be conducted to define the relationship between how resistance heaters contribute to winter peak.

Finding #6: In the Winter Peak Analysis and Solution Set report the consultant identified a significant difference in winter and summer DSM capacity, as shown in the table below from that report[53]. Most of the difference is from a past focus on residential programs that targeted summer peak, defined below as 916 MW vs. winter capacity of 14 MW, a difference of 902 MW. This difference in winter residential DSM capacity further compounds the future resource gap related the 2020 IRP Base Case with Carbon Policy Load Resource Balance discussed for DEC and DEP in this report at Figure 1 and Figure 2, respectively.

Table 39. Seasonal System DSM Capacity by Sector

Sector	Winter (MW)	% Winter	Summer (MW)	% Summer
RES	14	2.0%	916	54.1%
Small C&I	2	0.3%	11	0.7%
Large C&I	675	97.6%	767	45.3%
Total	692	100.0%	1,694	100.0%

Recommendation 1: Nearly all of Dukes residential winter capacity is related to small programs operating in and around Asheville. These are largely switch based programs that, by and large, do not overlap with the devices and control strategies discussed in this report and these programs should be reviewed for possible expansion beyond their current operating area.

Recommendation 2: Duke's residential summer DSM capacity is related to controlling AC loads. We expect that roughly 50% of this control capacity is installed on heat pumps and this program should be reviewed to clearly define if heat pumps enrolled in this program can be operationalized for us as a winter DSM resource. During the course of our work, we discussed this possibility with program staff but were unable to define a clear technical and programmatic path to enroll these systems for use in the winter, but this should be further explored.

Recommendation 3: In addition to the winter DSM programs defined in this report, Dule should develop an energy efficiency program targeting winter HVAC operations. This program would provide capacity savings incremental to DSM initiatives identified in this report while also serving as a platform to drive DSM measure adoption, which, by combining EE and DSM, we expect would enhance the program's overall cost effectiveness.

Finding #7: This research focused on the built environment but would benefit from research addressing the roll of residential new construction in mitigating the long-term trend in winter peak.

Recommendation: Duke should consider defining a pathway to partnerships with progressive home builders and technology providers to define opportunities to expand the use of EE and DSM in their design and how to scale grid connected DER technologies at the community level.

Finding #8: Our research was not able to fully define specific pathways to scale in DSM solutions in the rental markets, primarily the multi-family segments, including low-income customers.

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[53] Winter Peak Analysis and Solution Set report, Table 1 on page 12

Recommendation: Duke should consider defining a pathway to partnerships with progressive owners and operators of rental housing and how market innovations may help advance EE and DSM through both the single family and multifamily units, including approaches that might best serve low-income customers.

Finding #9: As discussed in the Winter Peak Analysis study and in this report at section 3.6.9 Market Potential and Participation Goals, the requisite data—including saturation of electric vehicles in the commercial and industrial market—was not available to estimate the market potential and participation of managed workplace and fleet charging.

Recommendation: EV managed charging represents a long-term DSM opportunity that should be the focus of future studies. Duke should begin defining how managed charging will operate during system winter peak coincidence, which will require:

- Profiling the market to help refine estimates of system interaction. This would include tracking development of load impacts from medium and large commercial trucks. This should inform the final design of EV Manage, including whether to prioritize workplace charging, fleet charging, or comprehensive commercial level 2 charging.
- Researching further which pilot program designs and incentive levels will best encourage load shifting during winter peak.
- Examining the potential for additional methods for managing future EV load, for instance EV TOU rates, TOU + rebate programs, and commercial EV tariffs with a super off-peak period. This should include researching the interactive effects among programs to determine which combination will cost-effectively address future EV demand during winter peaks.
- Identifying technology solutions for which pilot projects can be developed to test different approaches to managing EV charging.
- Defining economic benefits that help drive commercial adoption, thereby accelerating revenue growth.

Finding #10: Based on a review of preliminary results for the North Carolina Flex Savings Options Pilot, the pilot study is expected to provide residential load impacts during non-summer high and critical pricing event days for TOU and TOU + CPP rates which will greatly inform the final design of the TOU and CPP programs described in this report.

Recommendation: A similar pilot and evaluation should be conducted for Bill-Certainty/Fixed Bill Subscription, Bill-Certainty + PTR, and large C&I rates + PTR to inform the final program design. Objectives should include, but not be limited to:

- Understanding load impacts for these rates across different customer classes on high and critical pricing event days, average weekdays, and average weekends during the winter season.
- Assessing how different incentive levels cause customers to migrate among rates, for instance how many existing C&I demand response participants will prefer a PTR rate at various incentive levels.
- Testing innovative rates/tariffs including Fixed Bill that could offer multiple incentive levels based on the level of shared DER control.
- Researching how best to mitigate the impact of disruptive weather events (e.g., a polar vortex) in rates such as PTR where participation in events is voluntary.

Finding #11: During our research, we found a lack of segmentation and end use data for small, medium, and large C&I customers.

- **Recommendation 1:** Duke should undertake a Commercial End Use Survey (CEUS), similar the bi-annual Residential End Use Survey last completed in 2019. The design of a CEUS study should include defining saturation of both EE and DSM systems, such as commercial energy management systems that enable ADR solutions and also what additional backup generation resources might exist in the market that are not already enrolled in Dukes DSM programs.

- **Recommendation 2:** Duke should undertake a segmentation study of the C&I market and develop segmentation data that clarifies the potential for specific C&I sub-markets. Such as study should leverage Duke's emerging data analytics capacity to identify sub-markets that show high demand during winter peak periods, and also sub-markets that indicate a high likelihood of success in Duke's PowerShare and Demand Response Automation programs.

Appendix A. Programs Considered but Not Included

Table 40 below shows lists the programs that the Tierra Team considered but did not include in this report and the reasoning for each decision.

Table 40. Programs Considered but not Included

Segment	Name	Description	Concerns/Why Rejected
RES	Electric Resistance Space Heat DLC	Direct load control of ER heating	• Controlling baseboard electric resistance heating systems will not be cost effective due to the need install and control individual thermostats in multiple rooms per household • Research indicates that this is a small subsegment of the residential market • The proposed Smart T-stat DR program will acquire some of this potential winter peak demand reduction
RES	Cold climate heat pump	HP optimized for cold climates	• We don't expect that this technology will be cost effective in most of the Duke Carolinas' service territory due to currently high upfront costs
RES	IMBY Energy	Futuristic combined home appliance	• The IMBY System is envisioned to support electricity, heating, cooling, and hot water needs for residential and commercial buildings • Technically, the device will operate as a single device with a microturbine, heat pump, and heat transfer system integrated with heat storage and a chemical battery • The IMBY System is currently at an early research pilot stage, though it is a technology to watch
RES	HVAC thermal storage	Steffes ceramic brick grid-interactive electric thermal storage (GETS) system	• The Steffes GETS systems are not expected to be cost-effective in the Duke Carolinas' service territory due to high upfront costs and a mild winter climate
RES	HVAC heat pump thermal storage	Use ceramic or phase change materials to store space or water heat for peak periods	• Technology is currently at the early research pilot stage and not commercially available
RES	HVAC air balancing	Contractor service to optimize HVAC system performance to ensure that heating and cooling outputs are consistent	• Air balancing can provide energy savings and may be provided as part of the HVAC Winter Tune-up service • Vent air balancing can be overridden by occupants (adjust damper, etc.) which would reduce peak impacts • Peak savings from this service are not anticipated to be sufficient to warrant a separate program offering
RES	New single family and multi-family home DERs	New home builders specify technologies including smart t-stats, grid-connected water heaters, and "EV-ready" wiring	• This is a good strategy for a future phase for Duke Carolinas - not enough time to develop in current phase • The installation of DER technology in new SF and MF homes will not scale as quickly as in existing homes • Develop strategies to leverage current new Duke Carolinas' SF and MF homes programs
COMM SMB	Rate-enabled water heater controls	Like residential program, offered to SMB customers	• Controls and algorithms are currently designed for existing residential WHs and not for C&I • Consider this for a future phase and technology and applications expand to SMB market • Design the Rate Enabled Water Heater Controls program to allow for this application as the market expands
COMM SMB	Dispatchable emergency generators	Coordinate with SMB customers to dispatch existing emergency generators during peak demand periods	• This could be a good strategy for a future phase - not enough time to develop in current phase • Applicability and potential will be dependent upon field research and status of customer-owned assets
Large C&I	DSM/EE programs	All appropriate DSM technologies	• There are concerns that greater participation will lead to higher opt outs • Evaluate potential solutions and niche segments (municipalities, schools) in phase two • Determine if clients will opt into rates in return for participation in large C&I DSM/EE programs
Large C&I	Interruptible rates	Rates that permit Duke to request service interruptions of customers through demand response calls	• Discussions with Duke personnel indicate there are no gaps to be addressed by new interruptible rates

DUKE ENERGY

Winter Peak Analysis and Solution Set

December 2020

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Winter Peak Analysis and Solution Set

December 2020

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Winter Peak Analysis and Solution Set Overview

Duke Energy North Carolina and South Carolina engaged the Tierra Inc team to complete an analysis of winter peak conditions for the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems. This project included 3 scope of work tasks:

1. Winter Peak Analysis and Solution Set
2. Winter Peak Demand Reduction Potential Assessment
3. Winter Peak Targeted Reduction Plan

This report is scope of work tasks 1 of that contract with the objectives to:

- Review relevant documents and/or interview key Duke subject matter experts to align on specific metrics and parameters that define winter peak
- Define Duke residential market characteristics (e.g., segmentation) as related to winter peak (data provided by Duke or publicly available sources)
- Define Duke's non-residential market characterization (e.g., segmentation) as related to winter peak (data provided by Duke or publicly available sources)
- Summarize Duke winter peak coincident loads and residential/non-residential load shapes (data provided by Duke)
- Assess Duke's existing programs, technologies and delivery channels that target key end uses driving winter peak loads
- Coordinate with Duke's market potential study results and load forecast information

The report includes 7 sections:

1. A Summary of Findings that provides high level overview of key findings from each report section
2. A Peak Demand Overview that discusses utility level winter peak demand in 2018
3. A Current DSM Capacity section that presents a review of DEC and DEP current DSM capacity and identifies potential DSM program gaps
4. A Residential Market and Solutions section that reviews 1) rates applicable to the residential market, 2) an analysis of load profiles for key residential rates in 2018, 3) an analysis of residential market characteristics driving winter peak, and 4) a summary of the recommended solution set
5. Small and Medium C&I Market and Solutions section that reviews small and medium C&I customer loads and data and provides that same sequence of analysis discussed for the residential market
6. Large C&I Market and Solutions that reviews large C&I customer loads and data and provides that same sequence of analysis discussed for the residential market
7. Several Appendices that provide supporting material

This report forms the basis for inputs into scope tasks 2, Winter Peak Demand Reduction Potential Assessment, and 3, Winter Peak Demand Reduction Roadmap.

1. Summary of Findings

Peak Demand Overview

We reviewed hourly load data for 2017 and 2018 and identified the highest system coincident peak demand of 22,982 MW occurred in 2018 on January 5th at hour 8, with DEC and DEP contributing 14,397 MW and 8,585 MW, respectively, as shown in Figure 1.[1] We refer to January 5, 2018, as our study peak day.

Figure 1. Coincident Peak System Demand by Utility - Study Peak Day

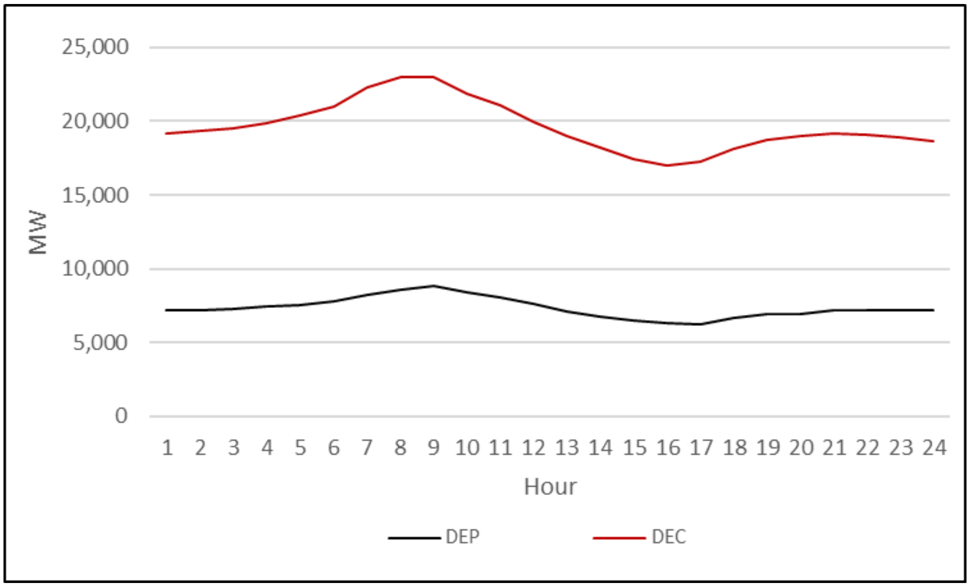


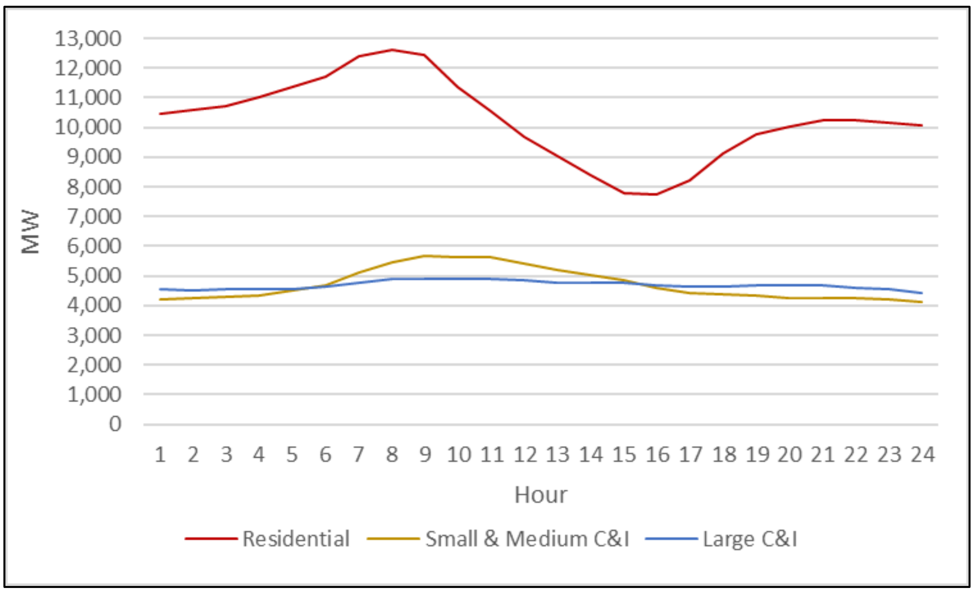
Figure 2 shows the aggregated DEC and DEP load profiles for the residential, small and medium C&I, and large C&I market sectors for the study peak day. The load profiles are overlaid on one another to illustrate the relative magnitude of each market segment indicating that the residential winter morning peak on our study peak day is about 2.5 times the size of either the small and medium C&I or large C&I sectors. We also reviewed the average demand for 6 winter peak days in 2018, shown in Figure 3, to get a sense of how demand for different rate classes and market segments varies. A comparison of this data provides several insights:

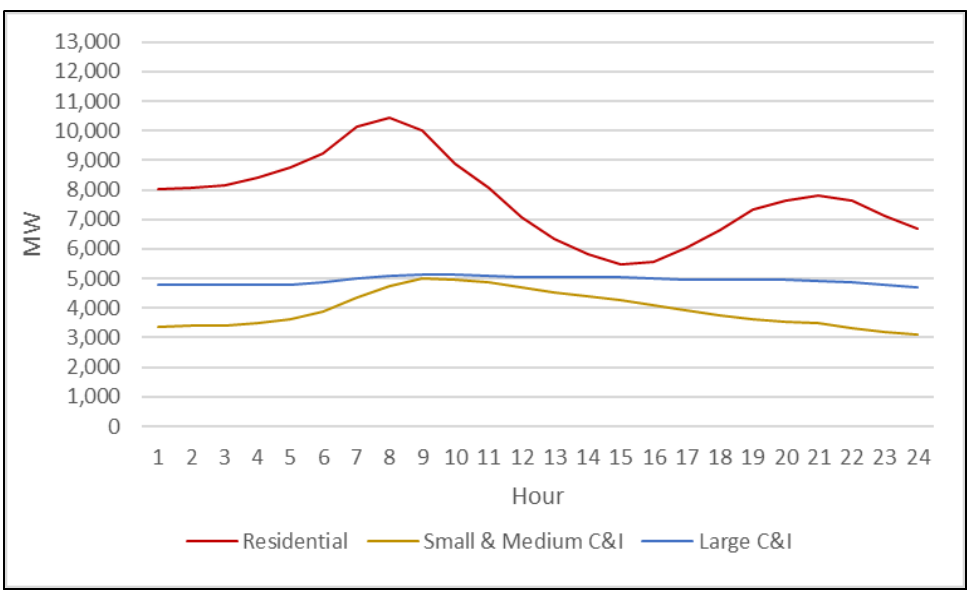
- Residential demand varies by about 4,000 MW between our study peak day and the average winter peak at hour 8, or a 33% increase, indicating the residential market is weather sensitive, likely within a fairly narrow temperature range. During the study peak day, residential customers accounted for 55% of total system demand between 7:00 a.m. through 9:00 a.m., while these same customers accounted for 47% of the average peak demand. In addition to loads from heat pump condensers in heating mode during cold days, such as the study peak day, we expect higher operating coincidence across dwellings and additional loads from other electric heaters, such as supplemental heat pump heat strips. We expect that these contribute to the difference between the study peak day and average winter peak.

[1] This does not include about 10,000 MW of wholesale obligations that are included in Duke's total system winter peak demand of approximately 33,000 MW.

- We divided the C&I market into customers in two cohorts, small and medium C&I and large C&I. Small and medium C&I demand begins to increase in the morning as businesses open and space heating becomes active. Demand varies by about 550 MW between our study peak day and the average winter peak at hour 8, or an 11% increase, indicating limited weather sensitivity. Large C&I customers include commercial facilities and the bulk of industrial loads which generally have demand in excess of 1,000 kW with customers that generally select TOU or RTP rate options. At the aggregate level, these customers typically have flat loads throughout each day and there was no change between morning demand when comparing the study peak and average winter peak day. There are, however, sub-segments within the large C&I segment that are sensitive to weather events and show viable DSM opportunities targeting heat loads.

Figure 2. Overlay of Demand Profile by Market Segment – Study Peak Day

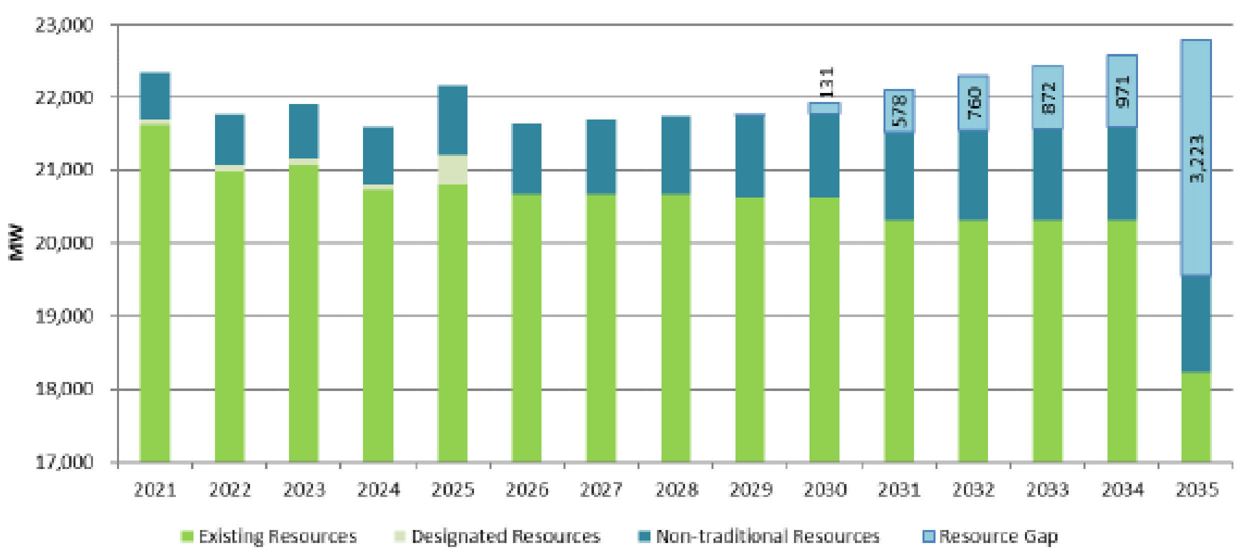




When planning and forecasting DSM solutions, there are several important considerations related to the winter system peaks shown in Figure 2 and Figure 3, including:

- When comparing and forecasting net peaks for summer and winter, the growth of large-scale solar generation will result in winter net peaks that are consistently higher than summer. As discussed in the 2020 IRP, new solar resources "economically selected to meet load and minimum planning reserve margin" account for about 1% for winter peak, versus a summer peak range of 10% to 25% of load[2]. This disparity is further defined in the Astrape Study[3] indicating that solar production is a small percentage of nameplate capacity during early morning winter peak periods. The gap between solar production as a winter resource compared to summer is highlighted in the Base Case with Carbon Policy discussion in the 2020 IRP[4], which notes that by 2035 solar only resources (i.e., net of storage) account for 1,232 MW of summer capacity versus 45 MW of winter capacity for DEP[5]and 1,242 MW of summer capacity versus 32 MW of winter capacity for DEC[6]. The resulting potential for resource gaps is present for both utilities, as shown for DEC in Figure 20[7] and DEP in Figure 21[8]. Higher winter net peaks and the potential for resource gaps support the need for additional winter DSM innovation and resources.

Figure 4. DEC Base Case with Carbon Policy Load Resource Balance (Winter)



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[2] Duke Energy Carolinas 2020 Integrated Resource Plan. TABLE 12-G, DEC – Assumptions of Load, Capacity, and Reserves Tables

[3] Solar contribution to peak based on 2018 Astrapé analysis

[4] Duke Energy Progress 2020 Integrated Resource Plan, Base with Carbon Policy at page 41

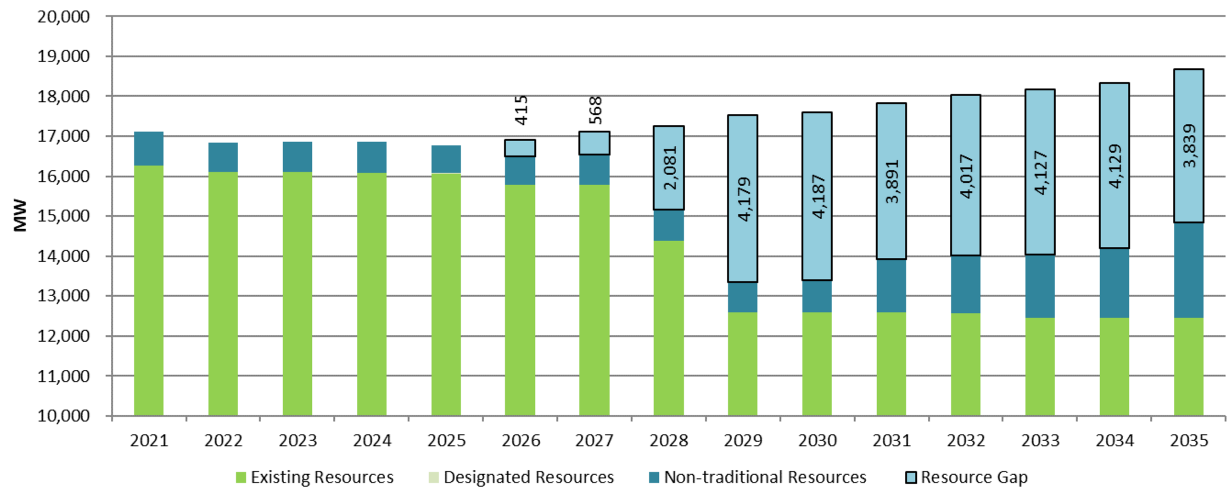
[5] Duke Energy Progress 2020 Integrated Resource Plan. Table 5-A. DEP Base with Carbon Policy Total Renewables

[6] Duke Energy Carolinas 2020 Integrated Resource Plan. Table 5-A. DEC Base with Carbon Policy Total Renewables

[7] Duke Energy Carolinas 2020 Integrated Resource Plan. Figure 12-E DEC Base Case with Carbon Policy Load Resource Balance (Winter)

[8] Duke Energy Progress 2020 Integrated Resource Plan. Figure 12-E DEP Base Case with Carbon Policy Load Resource Balance (Winter)

Figure 5. DEP Base Case with Carbon Policy Load Resource Balance (Winter)



- As discussed later in this report, winter peaks are primarily driven by residential electric space heating loads and these loads can be difficult to predict because of the way residential heat pumps work during their heating cycle. Heat pumps provide both space cooling and space heating and the condensers work the same in either the heating or cooling mode. However, most heat pumps systems also have supplemental resistance heaters that provide additional heating capacity when a dwelling requires more heat than the condenser can provide. This supplemental resistance heating can increase total heat pump demand by a factor of 3 (e.g., increase from 4 kW to 12 kW for a single home). This is discussed more fully in report section 4, Market Characteristics in the discussion preceding Figure 37. In short, the same home equipped with a heat pump might have three times the HVAC load in winter as it does during the summer, and while this disparity makes winter peaks harder to predict it is also shorter in duration than summer peak and can be effectively controlled through programmatic solutions.

Current DSM Capacity

To understand current DSM capacity[9] and define gaps, we reviewed data for 16 DSM programs currently in operation to assess the capacity of DEC and DEP to address winter peak events. Table 1 presents aggregate capacity by sector and season and this analysis shows that winter capacity of 692 MW is 41% of summer capacity of approximately 1,690 MW. DEC accounts for 64% of winter capacity, while DEP accounts for 36%. Approximately 98% of total winter capacity is from the medium / large C&I sector, with 2% of capacity coming from residential DSM programs operating primarily around Asheville, NC that controls electric space heating and water heating systems. Less than 1% is contributed through small C&I customers. Conversely, the residential sector accounts for 54% of summer capacity, virtually all of which is driven by controls on air conditioners.

Table 1. Seasonal System DSM Capacity by Sector

Sector	Winter (MW)	% Winter	Summer (MW)	% Summer
RES	14	2.0%	916	54.1%

[9] We define DSM capacity as the MW resource that can be delivered during a seasonal peak day regardless of the type of DSM dispatch (e.g., grid emergency)

Small C&I	2	0.3%	11	0.7%
Large C&I[10]	675	97.6%	767	45.3%
Total	692	100.0%	1,694	100.0%

For our analysis, we also binned Duke's DSM capacity by legacy programs that are rate based, and programs that are funded through the Energy Efficiency Rider (EE) rider. Table 2 shows that 50% of total winter capacity is supplied by legacy rate base programs and the balance funded through the EE rider programs which contribute 48% of capacity through the C&I sector and 2% from residential.

Table 2. DSM Capacity by Funding Source

Sector	Funding Source	Winter MW	% Winter MW	Summer MW	% Summer MW
C&I	Legacy Rate Base	344	50%	402	24%
	EE Rider	334	48%	376	22%
Res	EE Rider	14	2%	916	54%
Total		692	100%	1,694	00%

This distribution of program structures and funding sources has several implications:

- Legacy programs are very cost effective but have limited capacity to deliver additional winter DSM resource for a variety of reason:
  - Much of the legacy program capacity (and also capacity from rider-based programs) is appropriate as an occasional resource called on during grid emergencies but are unlikely to provide full relief during periods when events need to be called over multiple consecutive days, such as polar vortex events that may last up to a week. Because much of this DSM capacity relies on process interruptions for industrial customers, it's likely that many subscribers would drop the program or simply absorb the penalty rather than curtail load.
  - Since 2014, Duke has made an effort to provide day-ahead notification for winter events to the extent possible, however events are occasionally called with ~1-hour notification. This complicates resource calls occurring on winter mornings, when needed contacts may not be on-site or there isn't time to organize an operational response prior to peaks occurring around 8:00 a.m.
  - These programs are mature, several are closed, and the ability to add new capacity is limited because 1) many of the programs target large industrial customers and this load is decreasing[11] and 2) some of the DSM capacity is provided by large backup generators and this is a limited market that can also have regulatory restrictions, such as EPA rules about the use of backup generators to provide grid relief.
- Program based on the EE rider have shown increasing DSM capacity over time in the C&I sectors, but the ability to continue to expand capacity may be limited because current programs offer limited value to customers that 1) do not have significant backup generation or 2) do not have process loads that can be curtailed. As such, opportunities to shed non-critical building loads (e.g., HVAC, select lighting applications, etc.) are not present in the C&I DSM portfolio at any significant scale.

[10] This may include winter and summer capacity from customer on rates design for medium sized customers, as discussed in more detail and sections 5 and 6

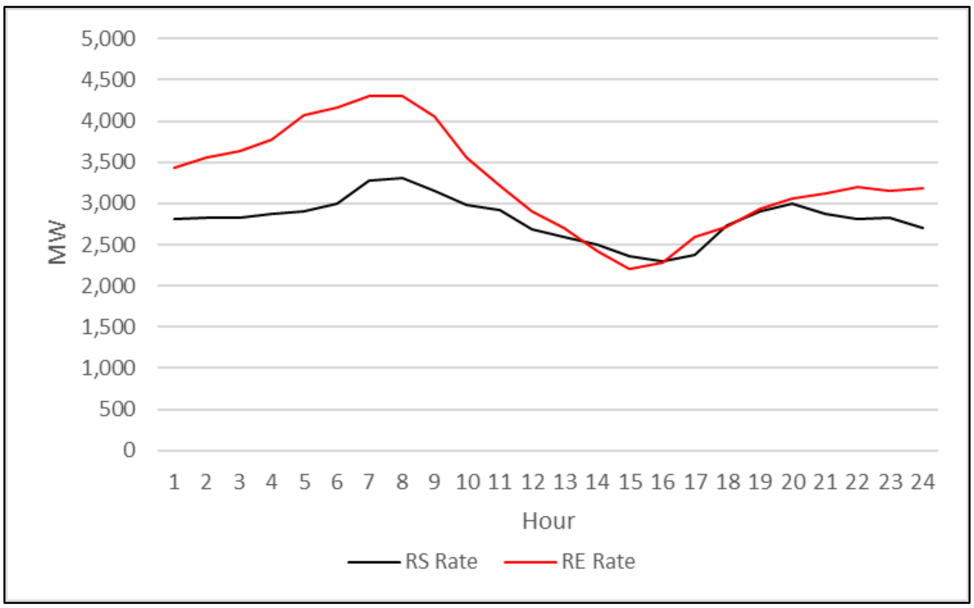
[11] For example, the MPS forecasts the industrial sector to decrease by 6% in NC and 11% in SC by 2044.

The following sections consider DSM opportunities for the residential and C&I market sectors and focus on mechanical solutions. The impacts of rate solutions are discussed more fully in the separate report on Task 3 of our scope, Assess the Winter Peak Demand Reduction Potential from Solution Set Programs.

Residential Market and Solutions

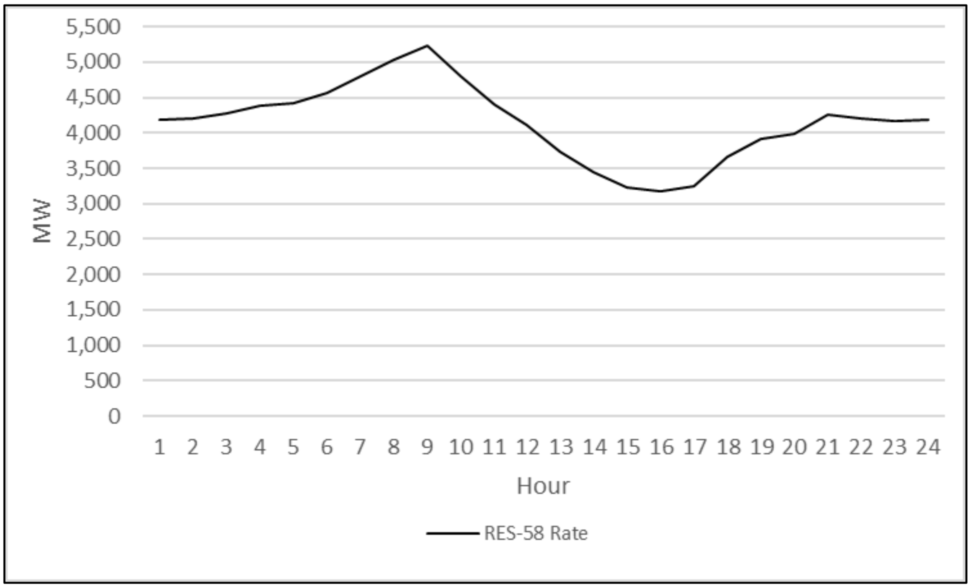
We analyzed various residential market characteristics, appliance saturation data, rates and load profiles for the residential market and concur with past conclusions that the residential winter morning peak demand is driven primarily by electric space heating, with some contribution for electric water heating. To gain a perspective on the magnitude of the impact of these heating loads, Figure 4 compares load shapes during our study peak day for customers with all electric homes on the DEC 'RE' rate (the red line), and customers on the 'RS' rate (the black line) which is used primarily by customers with gas heat and shows the impact of electric heating in the early morning and late evening.

Figure 6. DEC Residential Demand by Rate Schedule - Study Peak Day



DEP offers a single rate (RES-58) applicable to all residential customers and Figure 5 shows the demand profile on our study peak day, indicating an 8:00 peak. Based on our review of the 2019 RASS that shows that the saturation of heating systems is similar between DEC and DEP, we conclude that the DEP morning peak can also be attributed to electric space and water heating.

Figure 7. DEP Residential Demand by Rate Schedule - Study Peak Day

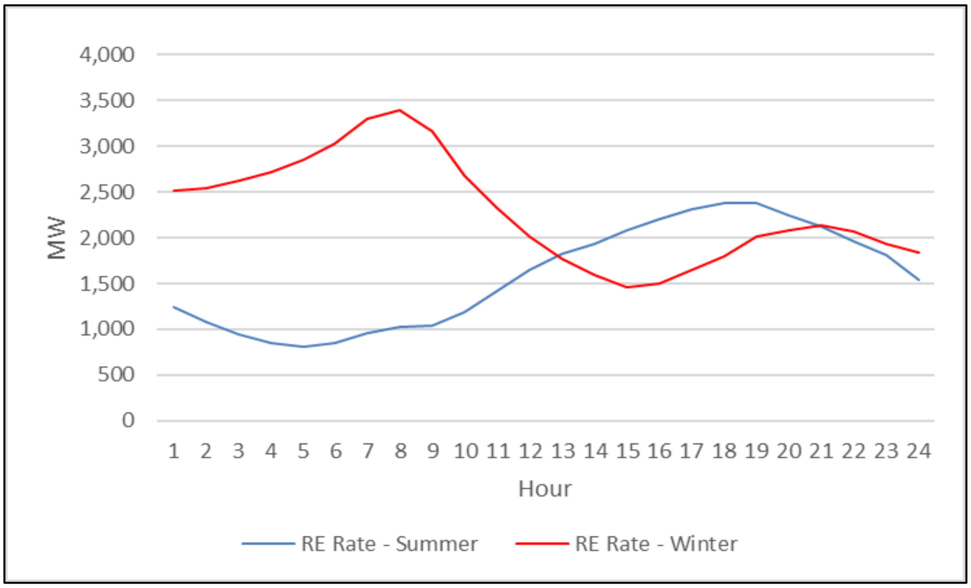


To gain a sense of the magnitude of the electric heating load and types space heating systems that drive peak demand, we also looked at the DEC all-electric 'RE' rate during summer and winter peaks, as presented in Figure 6 showing a difference between summer and winter average peak of 2,500 MW. Because other appliances, including hot water heating,[12] operate the same in winter and summer, we consider this seasonal difference to represent the average impact of electric space heating during peak days. In addition, because heat pump condensers work the same when heating in winter mornings as they do when in cooling mode on summer days, we would expect winter peak loads similar to summer cooling loads for electric homes if no other heating loads were present. However, Figure 25 shows that the average winter peak for electric homes exceeds the average summer by about 1,000 MW, or approximately 24% of winter morning demand from electric space heating. We attribute the addition winter load shown in Figure 6 to high operating coincidence on colder days and electric resistance heating sources other than heat pump condensers, including:

- Supplemental heat strips on HP heating system that adds incremental load to the HP condenser
- Electric wall furnaces
- Electric baseboard heaters
- Small supplemental plug-in heaters

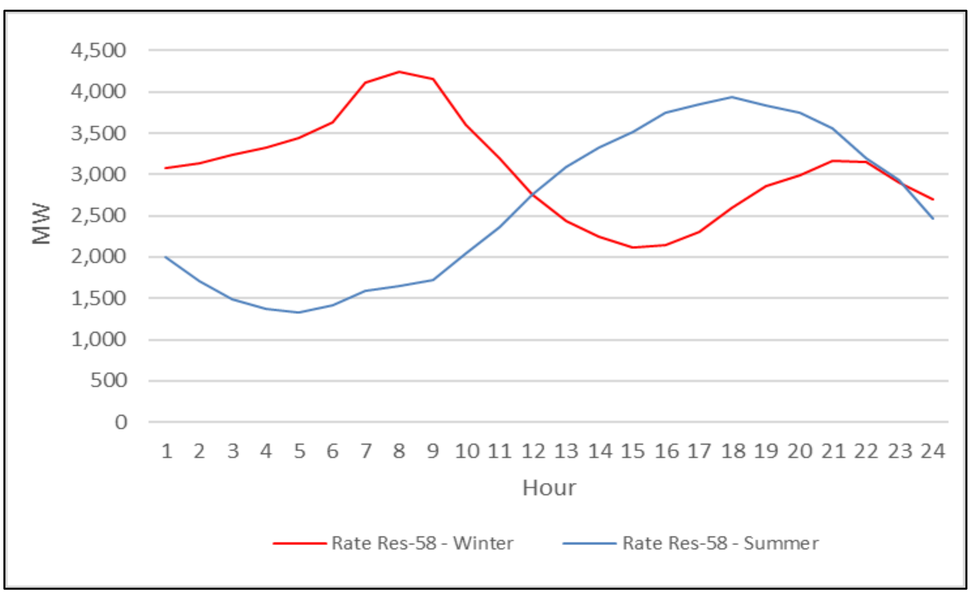
[12] Hot water energy use is generally consistent throughout the year because water usage patterns and groundwater temperature are generally consistent.

Figure 8. DEC RE Rate Season Comparison - Average Season Peak Day



We also compared the single DEP residential rate (Res-58) rate during summer and winter peaks as shown in Figure 7 and note the difference between summer and winter average peak is about 2,000 MW. We attribute this effect to winter electric space heating based on the same logic as DEC. When comparing winter and summer peak, we do not see the same magnitude of additional load for DEP as we saw with DEC, however, as noted previously, because appliance saturations are similar between the two utilities, we would expect to see a higher average winter peak. We consider this an ongoing research question but note that DEP is the only utility with a winter residential winter peak program in operation and this may account for part of the difference between the utilities.

Figure 9. DEP Res-58 Rate Season Comparison - Average Season Peak Day



To assess specific measures driving residential winter peak, we completed a modelling analysis using NREL's Building Energy Optimization Tool (BEopt[13]) to disaggregate residential heat pump and electric water heating loads during winter peak usage. Figure 8 is an example of the modelling outputs for a single-family medium electricity user during a peak winter day showing peak is largely driven by heat pump condensers, supplemental heat pump heat strips, and the fan used to deliver heat to the dwelling. Duke's 2019 residential appliance saturation survey (RASS) estimates that 46% of residential dwellings use heat pumps for space heating, and we estimate this represents about 1.7 million installed heat pumps. After accounting for operational coincidence,[14] we estimate these systems contribute about 4,800 MW of winter morning demand.

Figure 10. Single Family Peak Load Profile – Medium User

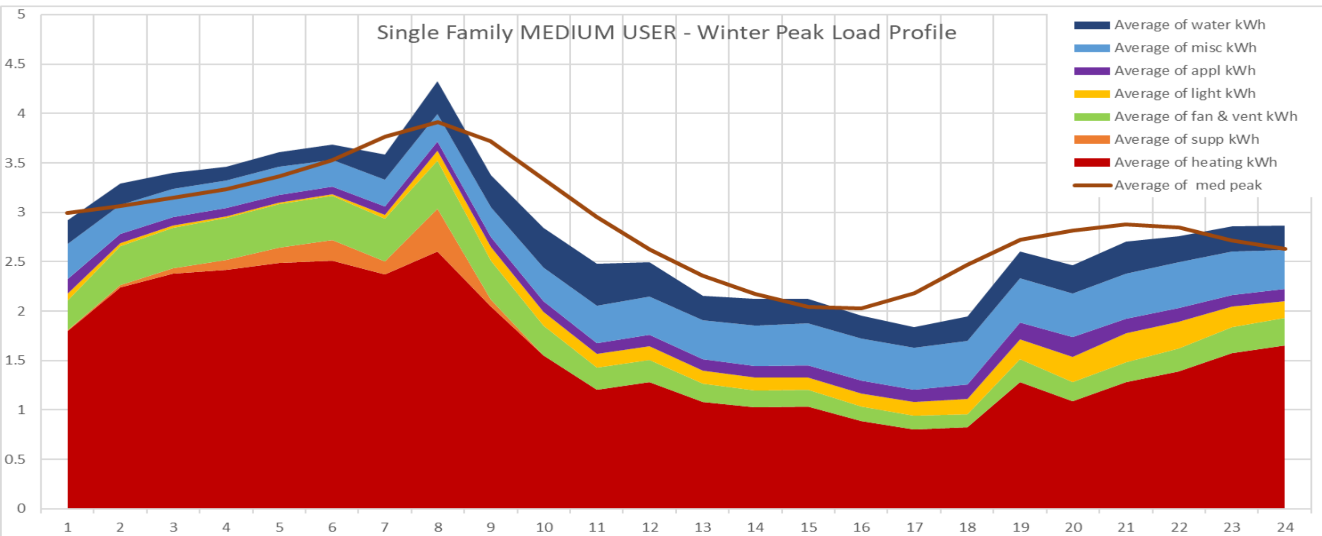
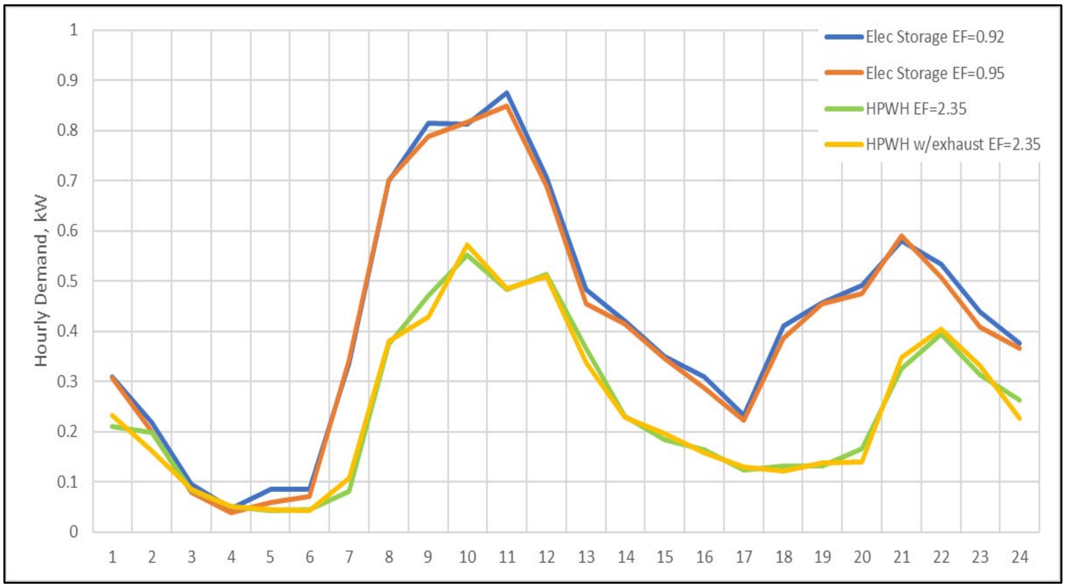


Figure 9 is the modelling output for electric hot water heaters (HWH) showing that electric resistance water heaters require about 0.8 kW per unit during morning peak hours. Duke's 2019 RASS indicates 71% of dwellings use electric HWH, and we estimate this represents about 2.5 million installed resistance water heaters. After accounting for operational coincidence, we estimate these systems contribute about 1,300 MW of winter morning demand.

[13] At https://beopt.nrel.gov/home

[14] The number of units operating at the same time

Figure 11. Modelled Electric Water Heater Load Profiles



Based on the preceding analysis, the proposed residential sector solution set targets demand related to winter morning electric space heating and other building systems and includes the following:

- Thermostat solution's that adjust heating set points, including
  - Bring Your Own Thermostat
  - Rate Enabled Thermostats
- Rate Enabled Residential Hot Water Heating Controls that automatically control how hot water heaters operate during peak times as defined though time of use rates
- Winter Heat Pump Tune-up that optimizes heat pump operation during winter periods, reducing both demand and energy usage

These solutions are discussed in detail in the Winter Peak Targeted DSM Plan task defined in our scope of work. Based on our review of market data and unit savings, Figure 10 shows our expected cumulative aggregate 10-year savings trends for the thermostat solutions, with maximum savings in year 10 of the forecast (2031) of 330 MW in hour 7. We defined a three-hour window during which thermostats would be controlled and savings decline in subsequent hours as homes being controlled during peak times increasingly call for heat. Figure 11 presents a similar forecast for rate enabled hot water heaters. We also defined a three-hour window during which water heaters would be controlled, however savings increase through the third hour as stored hot water supplies decrease until the maximum load shift occurs in hour 3.

Figure 12. 10-Year Residential Thermostat Solution Savings Forecast by Hour

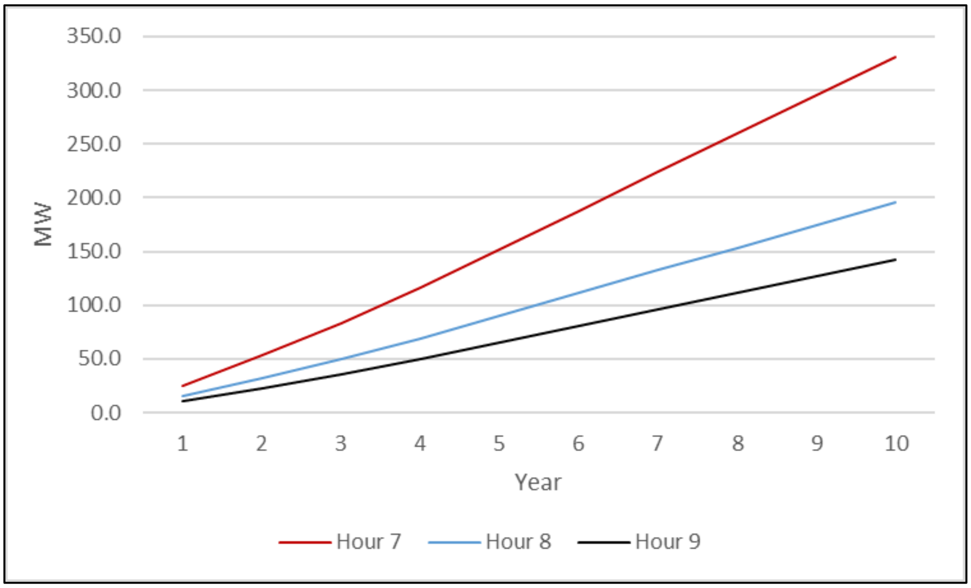
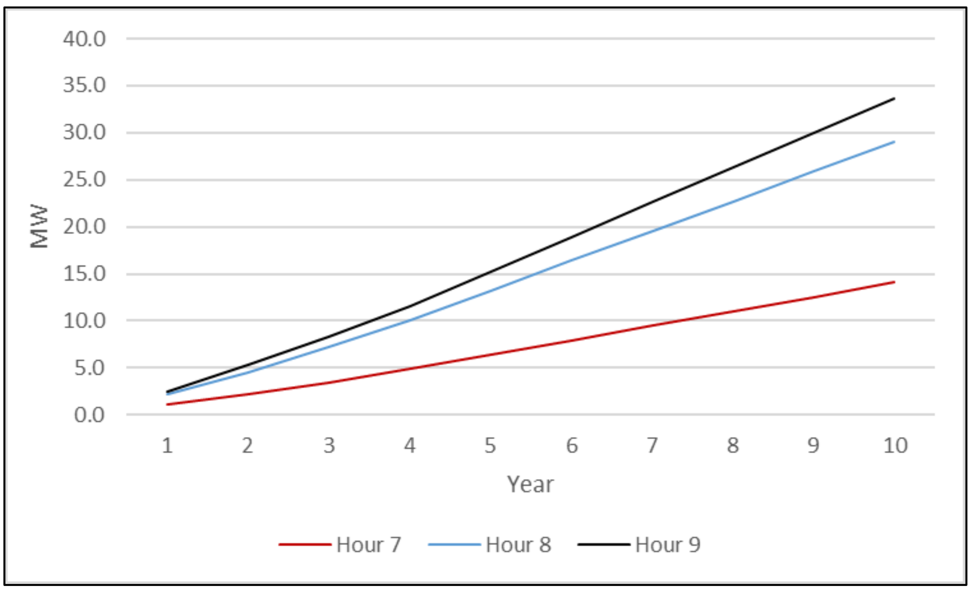


Figure 13. 10-Year Hot Water Heating Savings Forecast by Hour



In addition to the solutions we modeled, other solutions considered but not analyzed include:

- Replacing electric resistance water heaters with heat pump water heaters is a viable DSM solution. Duke currently offers rebates on this measure; however, we did not assess how the program adoption forecast would impact peak nor did we review the MPS to define how this measure factored into their residential DSM scenarios.
- Home battery solutions will likely play a role in residential DSM; however, we did not pursue modelling this solution until additional research can be completed on cost-effectiveness and operational considerations.

C&I Market and Solutions

Based on analysis of load profiles, rate structures and DSM program capacity, we disaggregated the C&I market into two cohorts:

- Small and Medium C&I: These are customers participating in rates that do not have a time differential component. Many of the customers are small to medium size, but there are larger commercial and industrial customers participating as well. However, this is a relatively small load, and the majority of this load is on the same flat rate design as the small and medium C&I customers. There are several TOU rates available to these customers and we have included this in our analysis of flat rate customers because these are pilot rates or participation is a small percent of the small-medium C&I load.
- Large C&I TOU customers – these are customers participating in rates that do have a time differential component and, in general, these will be larger C&I customers that meet the demand or energy usage threshold criteria for each rate.

The following discussion provides highlights from our analysis on each C&I cohort.

Small and Medium C&I

We reviewed data on 6 tariffs in the small and medium C&I cohort. Figure 12 is an example of our general approach to reviewing load shapes for each rate that compares the average load shape for the DEC small commercial general service flat rate (SGS) for six winter and four summer peak events in 2018. This load shape is typical of commercial customers indicating winter load begins to ramp up around 7:00 a.m. as businesses begin to open, peaking later in the morning than residential, and then falling off to a steady load after 5:00 p.m. We consider that the morning peak trend is driven primarily by electric space heating though this load is muted because there is a large diversity of operating and heating needs within the commercial segment when compared to the residential market (i.e., heating system operating coincidence is lower than the residential market). The summer load shapes presented in Figure 12 begin ramping at the same time but continue to grow throughout the day as AC systems become active in the afternoon. As such, it's likely that solutions addressing the winter heat load ramp will also offer a significant impact on summer AC demand.

To understand the range of winter peak impacts, Figure 13 compares demand between the study peak day and the average winter peak days for this same rate, showing a difference of 218 MW for the SGS, or an increase of about 23% between the annual and average winter peak day. All rates reviewed across both utilities showed some difference between the study and average peak day, indicating all have some heat load sensitivity to weather events, with rates targeting primarily industrial customer showing the least sensitivity to weather events. Across all DEC and DEP small and medium C&I customers, we estimate the morning heating load to be approximately 830 MW.

Figure 14. DEC 2018 SGS Demand Profile – Average Season Peak Day

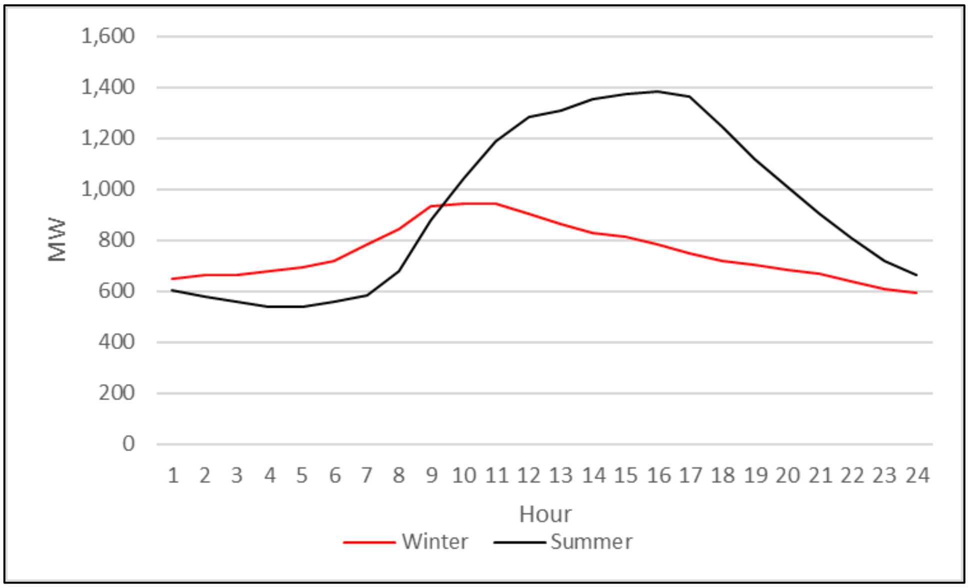
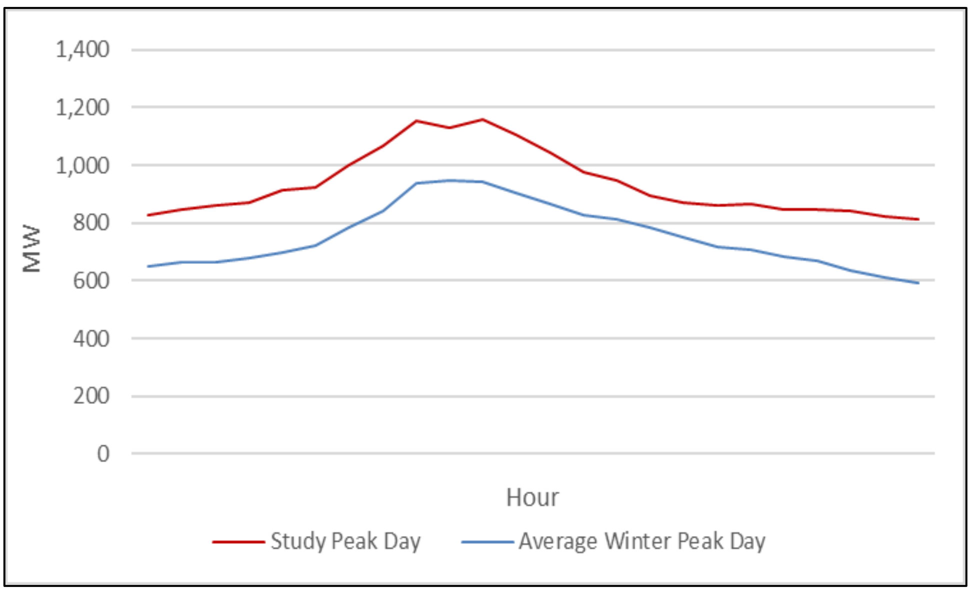


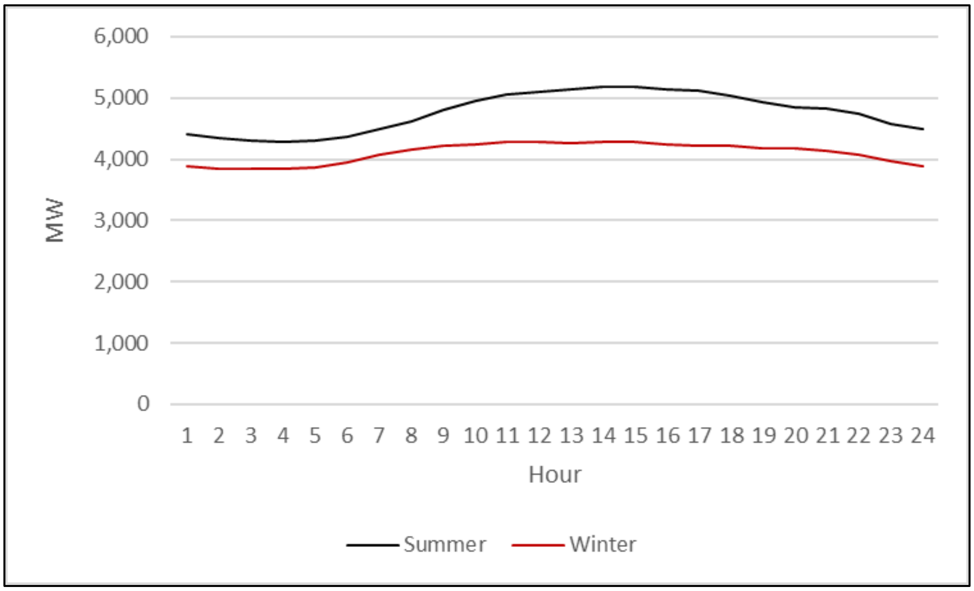
Figure 15. DEC 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



Large C&I

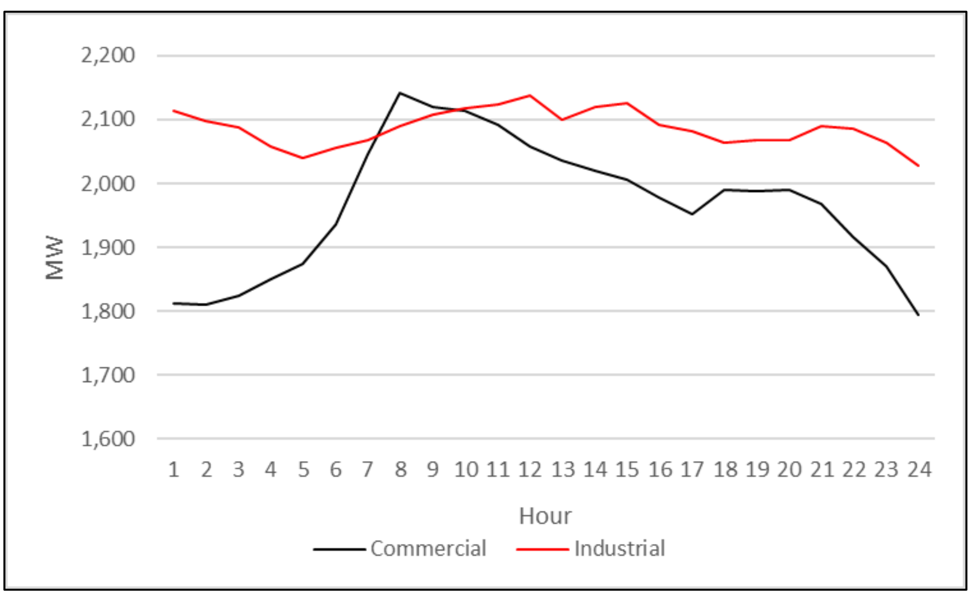
We reviewed the optional TOU rates offered to DEC customers, and the RTP rate offered to DEP customers and Figure 14 shows the demand prolife for the DEC optional C&I TOU rate during the 6 winter and 4 summer events we analyzed. At the aggregate rate level, this profile is generally flat every day, with an additional summer load of around 900 MW which we expect is largely drive by AC, refrigeration, and industrial production loads.

Figure 16. Average DEC 2018 C&I Optional TOU Rate – Average Season Peak Day



We also disaggregated the DEC optional C&I TOU rate into commercial and industrial loads, as shown in Figure 15, which shows that commercial customers have a typical commercial building demand profile where load begins ramping early and accelerates beginning at 6:00 a.m. with a peak around 8:00 a.m., which is coincident with the residential load shape discussed in Figure 4. We analyzed the commercial data and estimate that demand is driven primarily by heating and represents a load of approximately 155 MW. As discussed in the Current DSM Capacity section of our report, we believe this commercial load profile is not being addressed in the current set of DSM programs. Industrial TOU customers have much flatter loads throughout the year, though summer loads are higher which we attribute to AC, refrigeration, and production activity.

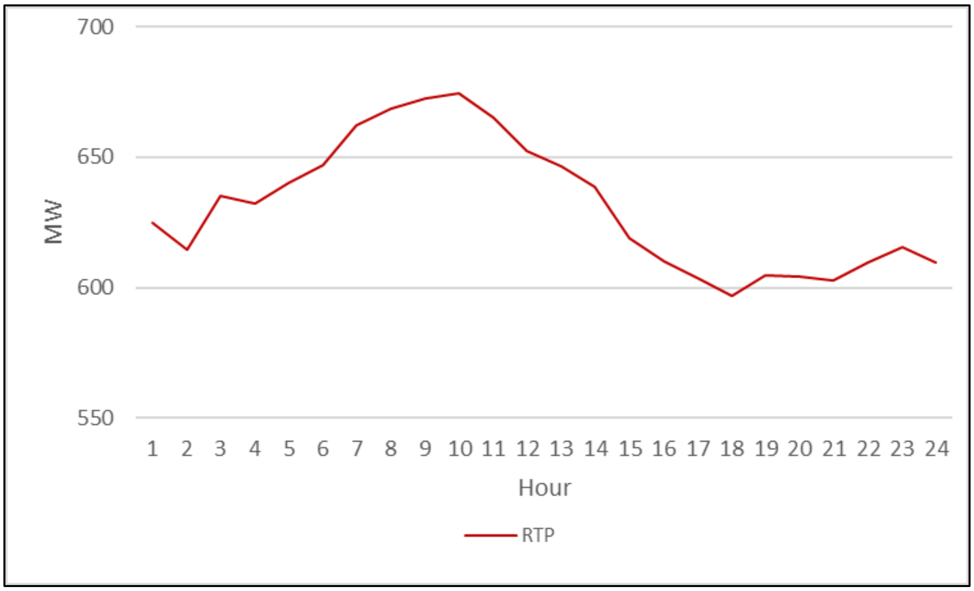
Figure 17. DEC C&I Optional TOU Rate Demand by Segment – Study Peak Day



We also reviewed load data for the DEP RTP rate and Figure 16 shows the study peak day. This figure adjusts the scale to emphasize the load shape and shows peak demand between 7:00 a.m. and 11:00 a.m.

Like DEC, we analyzed the data underlying Figure 16 and observed that this morning usage is primarily related to heating and represents a load of approximately 41 MW. However, DEP does differentiate between commercial and industrial customers, so we consider this a soft number and identified market segmentation as an ongoing research topic.

Figure 18. DEP RTP Rate Demand – Study Peak Day

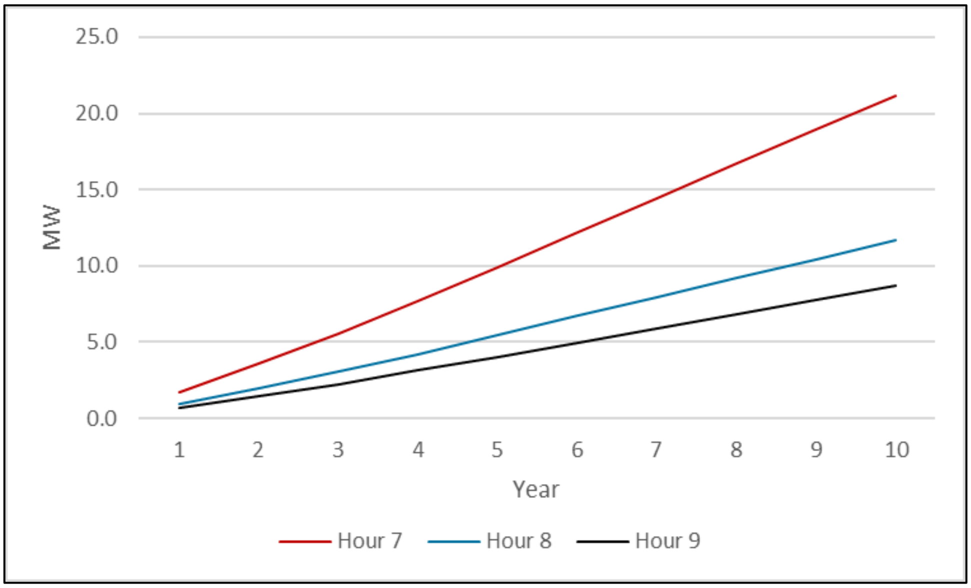


Based on the preceding analysis, the proposed C&I solution set targets demand related to winter morning electric space heating and other building systems and includes the following:

- For small and medium C&I, the solution set recommendation includes the same measures presented for the residential sector, with the exception of an electric hot water heating solution, and includes:
    - Bring Your Own Thermostat
    - Rate Enabled Thermostats
    - Winter Heat Pump Tune-up

  Figure 17 shows our expected cumulative aggregate 10-year savings trends for the thermostat solutions, with maximum savings in year 10 of the forecast (2031) of 22 MW in hour 7. Similar to the residential thermostat solutions, we defined a three-hour window during which thermostats would be controlled and savings decline in subsequent hours as businesses being controlled during peak times increasingly call for heat.

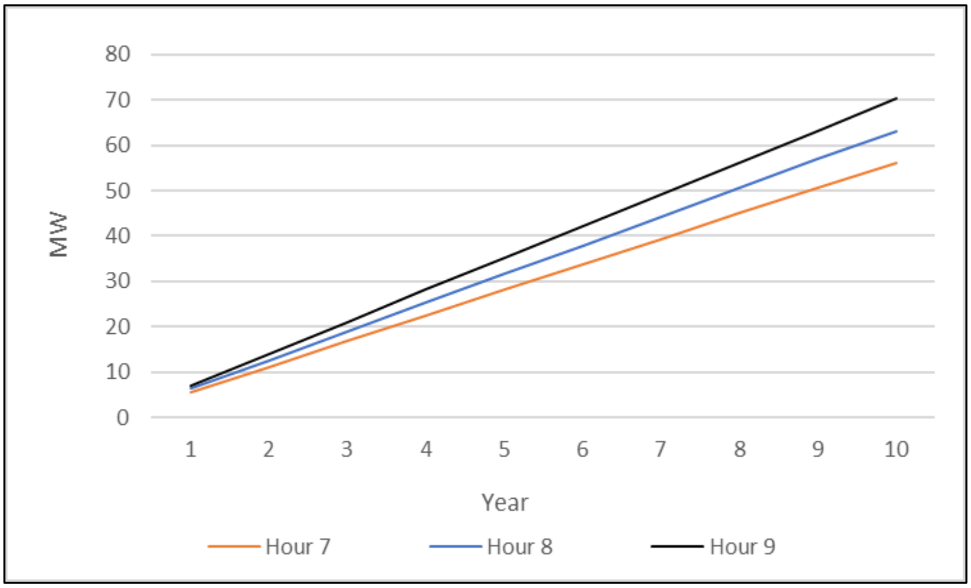
Figure 19. 10-Year Small Commercial Thermostat Solution Savings Forecast by Hour



- For large C&I customer our solution set is an automated demand response (ADR) program. ADR programs involve a combination of innovative rates, programs and technology solutions where customers may choose from among different options designed to fit their needs. This solution may also apply to medium sized customers. ADR technology solutions typically require that participants have, or install, equipment that can be controlled remotely, such as a building energy management system that automatically adjust equipment operating parameters in response to pricing signals from advanced rates, such as critical peak pricing or peak time rebate offers. An ADR solution provides the following enhancements to Dukes current C&I DSM portfolio:
  - Fill Gaps in the Current C&I DSM Offering
  - Diversifies and expands the DSM resource mix
  - Leverages Duke's emerging data infrastructure
  - Expands both winter and summer demand response capacity
  - Provides a pathway for expanded use of existing and emerging technologies for DSM applications

  Figure 18 shows our expected cumulative aggregate 10-year savings trends for the commercial ADR solutions, with maximum savings in year 10 of the forecast (2031) of 70 MW in hour 9, increasing from hour 56 MW in hour 7 as more commercial facilities become active.

Figure 20. 10-Year Medium & Large Commercial ADR Solution Savings Forecast by Hour



2. Winter Peak Demand Overview

System Peak

For this study we define winter months as October through May, and winter peak events as morning events occurring between the hours of 7:00 a.m. and 9:00 a.m. Daily peaks occurring in the afternoon during October through May are not included in our analysis of winter peak. We reviewed 12 peak days occurring in 2018. Table 3 shows that 8 peak days in each utility occurred in the winter months, and that 6 of these occurred in the morning (shown in red text). Throughout this document all references to the 'average winter peak day' load profile refers to the average of these 6 days.

The largest peak event for DEP occurred in the winter, while the largest winter peak event for DEC was the 3rd highest event, approximately 700 MW lower than its highest summer event. Of the 6 winter peak days in 2018, 3 days were common to both utilities and the remaining 3 events were separated by only a few days.

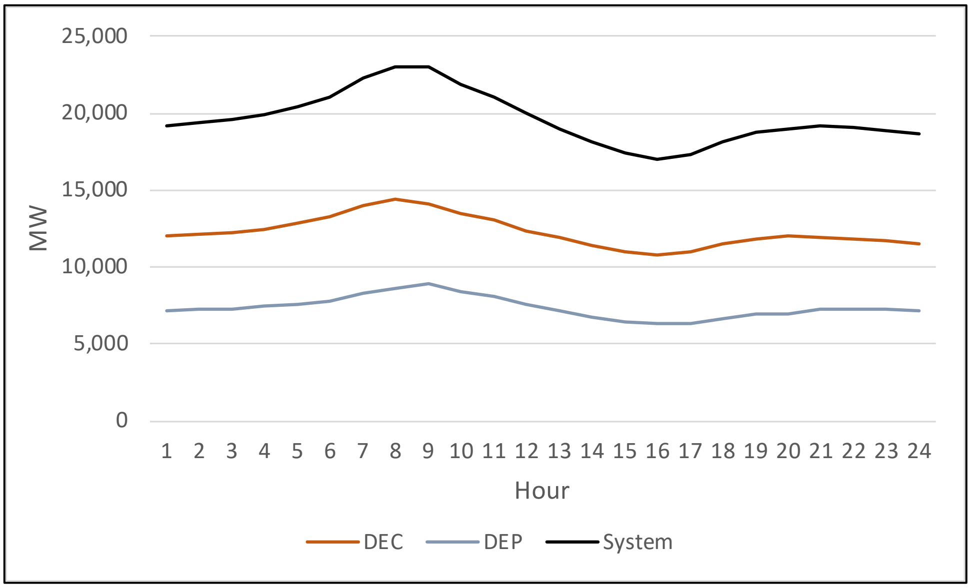
Table 3. 2018 Utility Peak Event by Season

DEC				DEP			
Season	Date	Hour Ending	Utility Total (MW)	Season	Date	Hour Ending	Utility Total (MW)
S	6/19	16	15,119	W	2/3	9	9,059
S	9/6	17	14,462	S	6/19	17	8,674
W	1/5	8	14,397	W	1/7	8	8,639
S	8/30	17	14,609	S	9/4	16	8,033
S	7/11	17	14,457	S	7/11	18	7,976
W	2/3	9	13,374	S	8/8	17	7,906
W	5/14	18	13,237	W	11/29	8	7,829
W	10/5	17	13,027	W	10/5	17	7,718
W	12/6	8	12,897	W	12/6	8	7,594
W	11/28	8	12,473	W	5/14	17	7,553
W	3/15	8	11,068	W	3/15	8	7,046
W	4/17	8	10,546	W	4/11	8	6,173

The highest coincident system peak demand for 2018 of 22,982 MW occurred on January 5th at hour 8 when DEC contributed 14,397 MW, shown in Table 3, and DEP contributed 8,585 MW.[15] Throughout this study we refer to this date as our ***study peak day***, and Figure 19 shows demand overlaid individually for each utility during the study peak day, and the combined total system.

[15] The highest DEP peak of 8,639 occurred two days later on January 7th at hour 8.

Figure 21. Coincident Peak System Demand by System and Utility – Study Peak Day



The system peak values shown in Table 3 are based on a review of customer sales data for Duke's retail customers and do not fully define the implication of net winter peaks. When comparing and forecasting net peaks for summer and winter, the growth of large-scale solar generation will result in winter net peaks that are consistently higher than summer. As discussed in the 2020 IRP, new solar resources "economically selected to meet load and minimum planning reserve margin" account for about 1% for winter peak, versus a summer peak range of 10% to 25% of load[16]. This disparity is further defined in the Astrape Study[17] indicating that solar production is a small percentage of nameplate capacity during early morning winter peak periods. The gap between solar production as a winter resource compared to summer is highlighted in the Base Case with Carbon Policy discussion in the 2020 IRP[18], which notes that by 2035 solar only resources (i.e., net of storage) account for 1,232 MW of summer capacity versus 45 MW of winter capacity for DEP[19]and 1,242 MW of summer capacity versus 32 MW of winter capacity for DEC[20]. The resulting potential for resource gaps is present for both utilities, as shown for DEC in Figure 20[21] and DEP in Figure 21[22]. Higher winter net peaks and the potential for resource gaps support the need for additional winter DSM innovation and resources.

[16] Duke Energy Carolinas 2020 Integrated Resource Plan. TABLE 12-G, DEC – Assumptions of Load, Capacity, and Reserves Tables
[17] Solar contribution to peak based on 2018 Astrapé analysis
[18] Duke Energy Progress 2020 Integrated Resource Plan, Base with Carbon Policy at page 41
[19] Duke Energy Progress 2020 Integrated Resource Plan. Table 5-A. DEP Base with Carbon Policy Total Renewables
[20] Duke Energy Carolinas 2020 Integrated Resource Plan. Table 5-A. DEC Base with Carbon Policy Total Renewables
[21] Duke Energy Carolinas 2020 Integrated Resource Plan. Figure 12-E DEC Base Case with Carbon Policy Load Resource Balance (Winter)
[22] Duke Energy Progress 2020 Integrated Resource Plan. Figure 12-E DEP Base Case with Carbon Policy Load Resource Balance (Winter)

Figure 22. DEC Base Case with Carbon Policy Load Resource Balance (Winter)

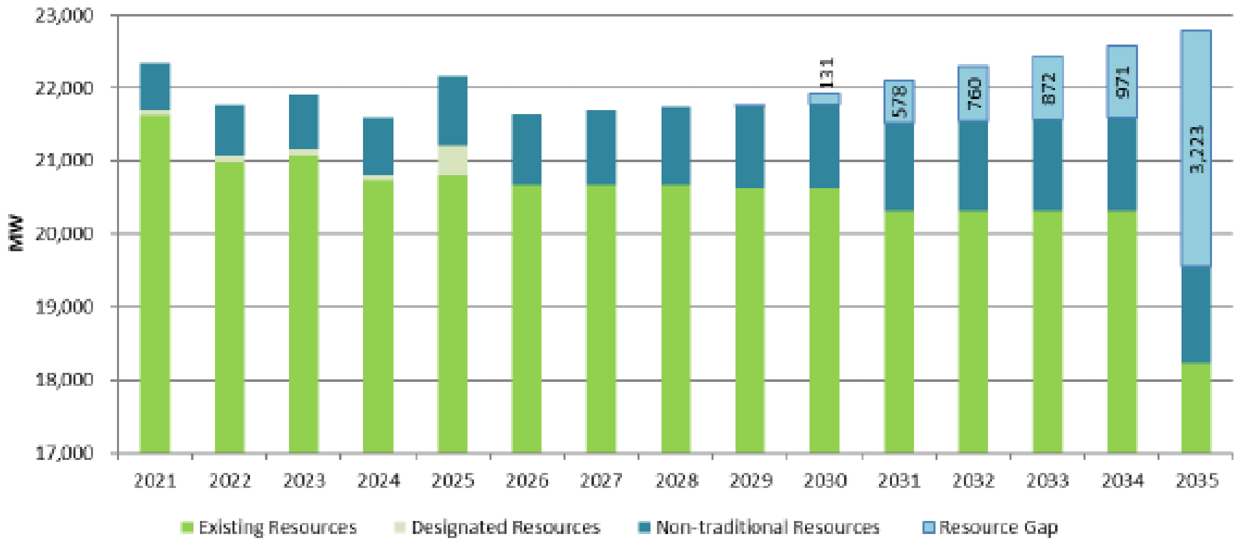


Figure 23. DEP Base Case with Carbon Policy Load Resource Balance (Winter)

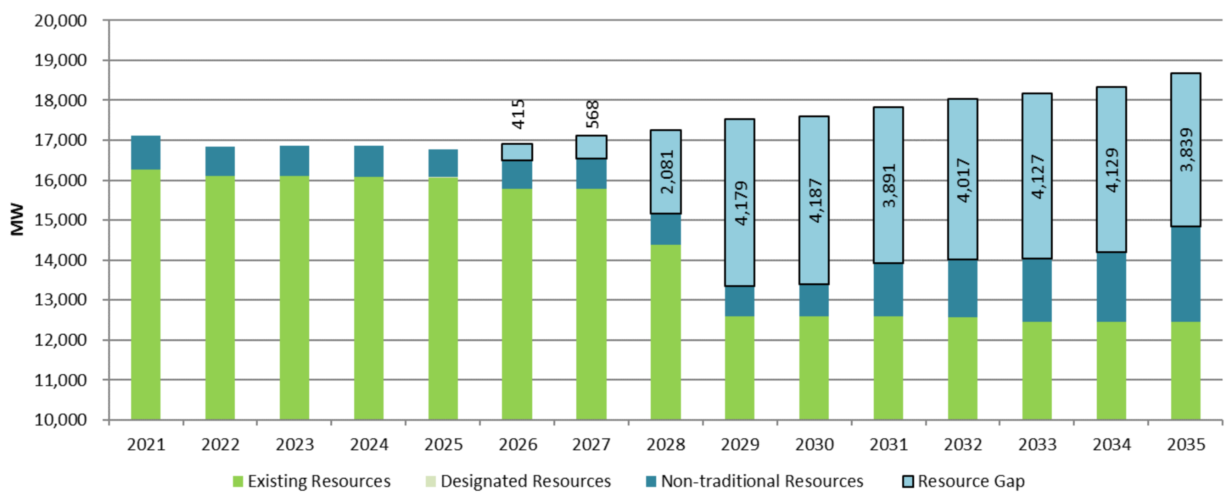


Figure 20 shows demand overlaid individually for each market sector on the study peak day, indicating that residential demand at hour 8 accounted for approximately 12,600 MW (54% of system peak), small to medium C&I sector accounted for 5,600 MW (25% of system), and large C&I accounted for 4,800 MW (21% of system) at that same hour.

Figure 24. System Coincident Peak Demand by Aggregated Segment Rate Class – Study Peak Day

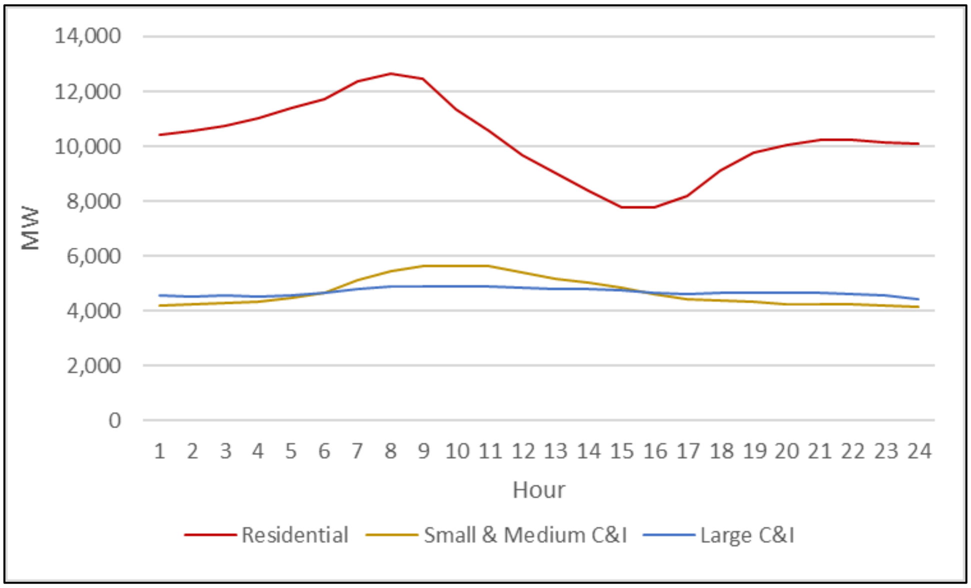


Table 4 shows the 3-hour peak event window for each rate class highlighted in green for the study peak day. This distribution of 3-hour events was common in all peak events reviewed and followed this sequence:

- Residential demand typically ramps sharply starting at 6:00 a.m., peaking between 7:00 and 8:00 and falling quickly after 9:00, in the case of our study peak day dropping by 1,100 MW (9%) between 9:00 and 10:00 a.m. Residential demand falls as commercial loads begin to build.
- C&I rate class peak lags residential peak by approximately 2 hours. As discussed later in this document, we categorized C&I rate classes for DEC as customers on the general service rates, and for DEP these are customers on the SGS, MGS, and LGS rates, including those participating in TOU offerings. This tendency indicates that load shifting in the C&I rate class might offset potential snapback from residential load mitigation activities.
- Large C&I loads represent DEC Option TOU and DEP RTP rates and vary by Commercial or Industrial customers. Industrial loads are generally flat throughout the winter and likely represent motor related loads. As discussed later in the report, commercial customers typically ramp significantly beginning at 5:00 a.m. and peak between 8:00 and 9:00, after which the load falls.   We suspect the morning commercial ramp is due to a high saturation of heap pumps.

Table 4. Top 3 Peak Hours by Rate Class – Study Peak Day

Hour	Res	Small / Medium C&I	Large C&I	Total
6	11,714	4,683	4,640	21,037
7	12,388	5,121	4,778	22,287
8	12,630	5,452	4,900	22,982
9	12,446	5,655	4,900	23,001
10	11,353	5,619	4,906	21,878
11	10,544	5,633	4,882	21,059
12	9,691	5,402	4,849	19,942

Rate Class Peak Summary

Figure 21 shows the load profile for various DEC rates and rate classes for our study peak day, including:

- Res RS rate – this is a residential rate used primarily by customers who have natural gas heating and appliances.
- Res RE rate – this is a residential rate for customers who have electric space heating and hot water heating systems (i.e., all electric homes).
- Small / Medium C&I – this includes an aggregated view of customers participating in various flat rates for small and medium customers though it may also include some industrial rates and customers that are on flat rates or those with demand and usage that do not qualify for rates we modelled for large C&I customers.
- Large C&I – this includes an aggregated view of commercial and industrial customers participating in DEC optional TOU rates.

Figure 21 shows an overlay of the load profiles for each rate class and illustrates that during the system peak between 7:00 and 9:00 a.m., demand from the residential rate for customers with all electric homes (RE) is the primary driver of the DEC peak. The RS sate shows some morning peak, but this is small, driven by household appliances other than space and water heating. All commercial rates peak later in the morning, with only a slight peak for C&I TOU customers, which include the bulk of industrial customers. Figure 22 provides the same analysis for the average of 6 winter peak events illustrating the same general shapes but showing a smaller impact from the residential RE and RS rates.

Figure 25. DEC 2018 Demand by Rate Class – Study Peak Day

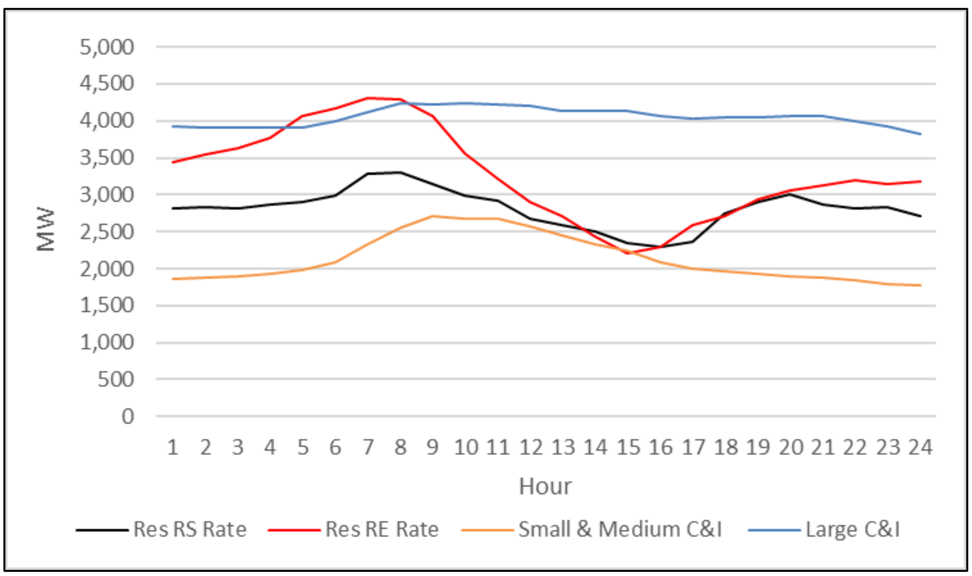


Figure 26. DEC 2018 Peak Demand Profile by Rate Class - Average Winter Day

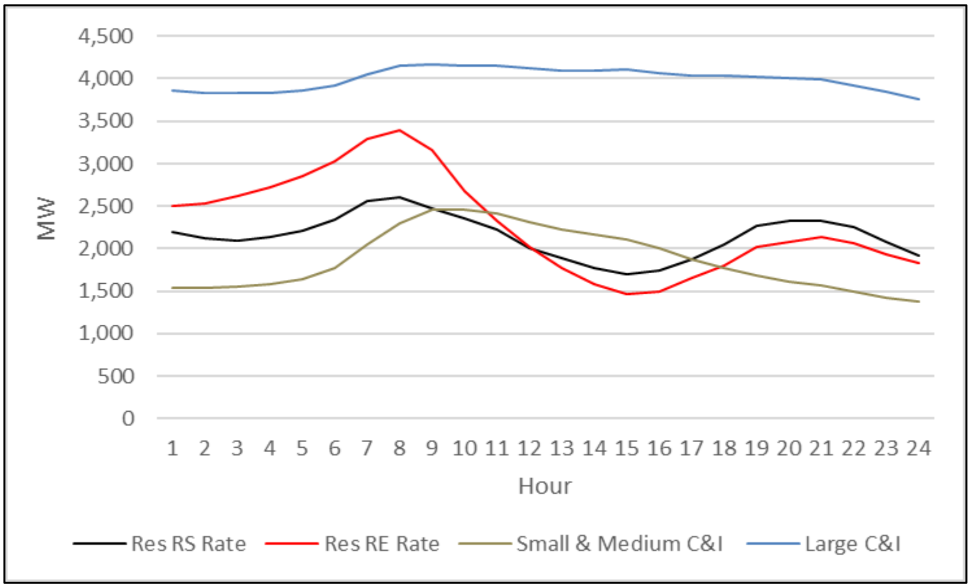


Figure 23 shows the load profile for various DEP rates and rate classes for our study peak day, including:

- Res rate – this curve shows the total residential load based on DEP's single residential rate except for several small TOU pilots that accounted for less than 3% of residential load.
- Small & Medium C&I - this includes an aggregated view of customers participating in various DEP general service rates that do include a time differential. These are flat rate variants with the same customer criteria as the SGS, MGS and LGS TOU rates.
- Small & Medium C&I TOU – this includes an aggregated view of customers participating in various DEP optional TOU rates, including SGS, MGS and LGS customers.
- Large C&I – this is a C&I real time pricing rate used primarily by large industrial customers with limited space heating demand.

Like the previous DEC analysis, Figure 23 shows the load profile for each DEP rate class. It illustrates that during the system peak between 7 and 9, the Res rate exceeds demand for all other customers by a large margin and is the primary driver of the DEP peak. Figure 24 provides the same analysis for the average of 6 winter peak events. It illustrates the same general shapes and shows that residential usage is consistently higher than all C&I other rates and rate classes.

Figure 27. DEP 2018 Peak Demand by Rate Class – Study Peak Day

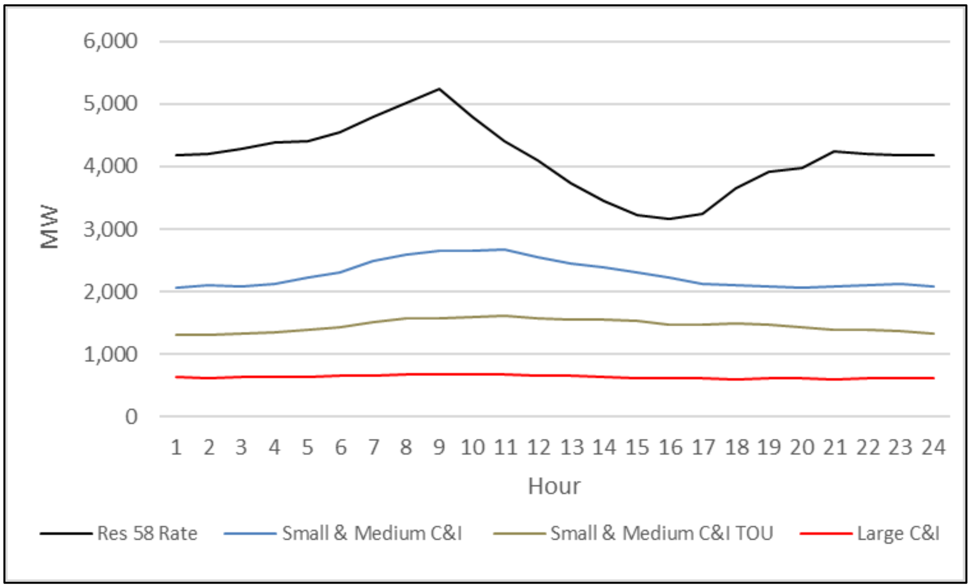
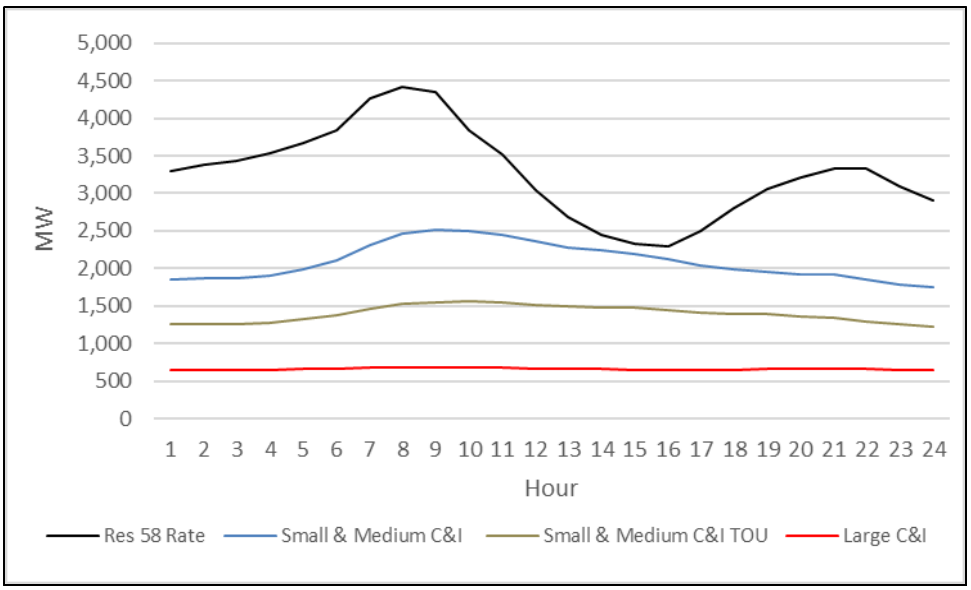


Figure 28. DEP 2018 Demand Profile by Rate Class - Average Winter Peak Day



The report sections discussing the residential and C&I sectors provide additional details on the rates and loads shapes, including disaggregating rates that have been combined for comparison purposes in the preceding figures.

3. Current DSM Capacity

Table 5 provides a snapshot of 16 DSM programs currently offered, including their winter and summer capacity based on key performance indicators (KPI) and DSM Scorecard values. We refer to this as a snapshot because actual DSM capacity varies from day to day and hour to hour, and the values in Table 5 are indicative of the relative magnitude of capacity available for comparison purposes across programs, not the actual resources available at any given point in time. Additional details on large C&I sector DSM programs can be found in Appendix 3, DSM Program Structures and Types. The following discussions highlight several observations from the DSM capacity summarized in Table 5.

Table 5. DSM Capacity Snapshot

Utility	Sector	Program / Rider	Winter (MW)	% Winter	Summer (MW)	% Summer	Cost Recovery
DEP	Large C&I	LLC	72	10%	111	7%	Legacy Rate Base
DEP	Large C&I	68	0	0%	0	0%	Legacy Rate Base
DEP	Large C&I	IPS	4	1%	7	0%	Legacy Rate Base
DEP	Large C&I	57	16	2%	23	1%	Legacy Rate Base
DEP	Large C&I	NFS	7	1%	7	0%	Legacy Rate Base
DEP	Large C&I	LGS-CUR-TOU	67	10%	81	5%	Legacy Rate Base
DEP	Large C&I	LGS-RTP Load Response	50	7%	30	2%	Legacy Pricing
DEC	Large C&I	IS	117	17%	132	8%	Legacy Rate Base
DEC	Large C&I	SG	10	1%	11	1%	Legacy Rate Base
DEC	Large C&I	PowerShare	322	47%	326	19%	EE Rider
DEP	Large C&I	DRA	0	0%	24	1%	EE Rider
DEP	Small & Med C&I	SB - EEDR	12	2%	14	1%	EE Rider
DEC	Res	PowerManager-NC/SC	0	0%	536	32%	EE Rider
DEP	Res	EnergyWise Home AC	0	0%	374	22%	EE Rider
DEP	Res	EnergyWise Home HS	8	1%	0	0%	EE Rider
DEP	Res	EnergyWise Home WH	6	1%	6	0%	EE Rider
		Total	692	100%	1,694	100%	

Table 6 shows that residential programs deliver 2% of winter DSM capacity while C&I delivers 97%. Conversely, residential programs provide 54% of summer capacity, primarily because these programs were designed to address summer peak needs. As discussed in the Residential DSM Capacity section of the report, there are several technical and regulatory challenges in leveraging residential summer DSM capacity for winter use. Table 7 shows this data by utility, indicating DEP has no winter DSM capacity.

Table 6. Seasonal System DSM Capacity by Sector

Sector	Winter (MW)	% Winter	Summer (MW)	% Summer
RES	14	2.0%	916	54.1%
C&I	2	0.3%	11	0.7%
Large C&I	675	97.6%	767	45.3%
Total	692	100.0%	1694	100.0%

Table 7. Seasonal System DSM Capacity by Utility and Sector

Season	Winter				Summer			
Sector	Res	C&I	Large C&I	Total	Res	C&I	Large C&I	Total
DEP	14	2	231	248	380	11	286	677
DEC	0	0	444	444	536	0	481	1,017
Total	14	2	675	692	916	11	767	1,694

Table 8 shows winter and summer capacity by funding source indicating that DSM capacity is split evenly between legacy rate base and pricing programs, and programs funded through EE riders. As discussed in the large C&I Market section, most legacy DSM programs are either closed to new participants or have not grown due to various market factors, such as saturation of available customers or declining industrial capacity of some key market sectors, such as textile production.

Table 8. DSM Capacity by Cost Recovery Source

Sector	Cost Recovery	Winter MW	% Winter MW	Summer MW	% Summer MW
C&I	Legacy Rate Base and Pricing	344	50%	402	24%
	EE Rider	334	48%	365	22%
Res	EE Rider	14	2%	916	54%

The following sections provide further detail on residential and C&I DSM capacity.

Residential DSM Capacity

Residential DSM capacity presented in Table 5 is achieved by several programs that are funded through residential EE riders that vary by utility and state. The programs funded through these riders funding residential DSM capacity include:

- EnergyWise Homes
  - DEP NC Rider LC-SUM-5 is available to all residential service schedules. Participating Customers may choose to employ (1) Company-provided Load Control Device(s) or (2) eligible Customer-owned thermostat(s) to interrupt service to each approved electric central air conditioning unit and/or electric heat pump, as well as to monitor their operation under the provisions of this Rider. The Company shall be allowed, at its discretion, to interrupt service to each air conditioner for up to four hours during each day of the summer control season (May through September). Air conditioner interruptions are limited to a total of 60 hours during any one summer season.
  - DEP NC Rider LC-WIN-2B is only available in the Company's Western Region service territory in the area surrounding Asheville. Duke installs controls to (1) interrupt service to all resistance heating elements installed in approved central electric heat pump units with strip heat and/or (2) interrupt service to each installed, approved electric water heater. Resistance heating element interruptions shall be limited to a total of 60 hours during any one winter season (December through March).
  - DEP SC Rider LC-SUM-6 is available in conjunction with all residential service schedules. Participating Customers may choose to employ (1) Company-provided Load Control Device(s) or (2) eligible Customer-owned thermostat(s) to interrupt service to each approved electric central air conditioning unit and/or electric heat pump. The rider allows for the interruption of service to each air conditioner for up to four hours during each day of the summer (May through September). The Company reserves the right to have longer interruptions in the event continuity of service is threatened. Air conditioner interruptions shall be limited to a total of 60 hours during any one summer season.
- Power Manager
  - The DEC Rider Power Manager Load Control Service is available in North and South Carolina. Participating Customers may choose to employ (1) Company-provided Load Control Device(s) or

(2) eligible Customer-owned thermostat(s) to interrupt service to each approved electric central air conditioning unit and/or electric heat pump, as well as to monitor their operation under the provisions of this Rider. The program can interrupt service to the customer's central air conditioning (cooling) systems at any time and has the right to intermittently interrupt (cycle) service to the Customer's central electric air conditioning (cooling) systems. Operation is restricted to an eighteen (18) hour period from 6:00 a.m. to 12:00 midnight, of which the total duration of a cycling interruption shall not exceed ten (10) hours.

Table 9 provides additional detail on the DSM scorecard values previously discussed at Table 5 and indicates that approximately 916 MW of summer capacity is available, of which 910 MW is related to air conditioning operation.

Table 9. Residential DSM Rider Winter and Summary Capacity[23]

System	Rider	Season	System Control	Winter Capacity (MW)	Summer Capacity (MW)
DEP	LC-SUM-5 and LC-SUM-6	May - Sept	AC, HWH	0	374
DEP	LC-WIN-2B	Dec - Mar	HP-HS, HWH	12	6
DEC	Power Manager Load Control Service	NA	AC & HP Cooling	0	536
			Total	12	916

The following are several observations regarding residential DSM capacity:

- Winter DSM capacity targeting residential electric heating is delivered by the DEP NC Rider LC-WIN-2B and is available to residents around Asheville. The 14 MW capacity associated with this rider includes 8 MW in supplemental HP heat strip control and 6 MW from HWH controls.
- The DEP EnergyWise Home AC program has approximately 374 MW of demonstrated summer capacity. The program does not distinguish between homes cooled by air conditioning condensers (i.e., natural gas heat combined with electric air conditioning) and HP cooling systems. Assuming program enrollment has been agnostic about whether cooling is provided from AC or HP condenser, we estimate that 52% (194 MW) of this capacity is provided by heat pumps that also provide heat in the winter.[24] Activating this capacity for winter use will be difficult because:
  - The installations use a switch that turns off the condenser and were wired in such a way that did not consider 1) coil icing risks in the winter and 2) shutting off the HP condenser alone would likely cause the system to call on the backup heat strip, resulting in a net increase in load for participating systems. We were not able to disaggregate how much of the 374 MW capacity is distributed across switch and thermostat devices.
  - The rider is specific about summer use only and would need to be revised, including the potential need to re-enroll exiting HP participants.
  - These challenges aside, it is conceivable that these customers can be enrolled in thermostat solutions that provide both winter and summer benefits though we did not consider the economic impacts of this or any uncertainty in potential loss or gain on DSM capacity in moving from a switch to a thermostat solution.

[23] KEY FILE -DEP and DEC res DSM 2020.06.13

[24] Based on Duke's 2019 Residential Appliance Saturation Survey study (RASS) saturation estimates shown in Table 23

- The DEP EnergyWise Home hot water heating (HWH) program operating around Asheville uses a switch that disables electric hot water heaters during winter peak events. This program accounts for 1% of our snapshot DSM capacity (Table 5), and HWH control is viable for expansion through either switch or rate enabled device controls. For forecasting purposes, switch controls and rate enabled devices would be competition groups, including the prospect that rate enabled devices would be used more frequently (i.e., daily curtailment based on a rate schedule), though net usage and revenue would be neutral for both switches and rate enabled devices because any water heat lost during an event would need to be made up during a recovery period.
- The DEP EnergyWise Home heat strip (HS) program is a switch that disables the HS during winter peak events and the rider limits its application to only the DEP NC around Asheville. This program accounts for 1% of our snapshot DSM capacity (Table 5) and is viable for expansion beyond this limited territory. If the heat strip program is expanded, it would be a competition group for thermostat solutions such BYOT or rate enabled t-stat options. Because this program engages only the HS, the savings are likely to be less than t-stat options that include shutting down the system (condenser, HS, and fan). We did not calculate the impact differential between switch and t-stat options but note that the average evaluated savings per DEP EnergyWise Home AC system[25], which includes summer impacts for the condenser only, is .096 kW versus 0.90 kW for supplemental heat strip only impacts under the DEP EnergyWise Home heat strip (HS) winter program[26]. As discussed previously, because shutting off a condenser in heating or cooling modes should yield similar results, these evaluations indicate that interrupting a HP condenser in the winter yields roughly the same results as interrupting a supplemental HP heat strip.
- Similar to the DEP Energy Wise Homes program, the DEC Power Manager program controls combination of HP and AC systems and reports 536 MW of summer capacity, though it does not define a savings value for winter events for HPs in heating mode. Assuming program enrollment has been agnostic about whether cooling is provided from an AC or HP condenser, we estimate that 42% (224 MW) of this capacity is provided by heat pumps that also provide heat in the winter based on 2019 RASS saturation estimates at Table 22. As with EnergyWise homes, it is conceivable that these customers can be enrolled in thermostat solutions that provide both winter and summer benefits though we did not consider the economic impacts of this or any uncertainty in potential loss or gain on DSM capacity in moving from a switch to a thermostat solution. The Power Manager Load Control Service rider does not limit operations to only summer and we assume that Power Manager customers using thermostats are available for winter operation.

Table 10 is a review of customer participation in various residential DSM solutions as of May 1st, 2020. Based on HP saturation data available from the 2019 RASS, we estimate that approximately 15% of all HP units are currently enrolled in a residential DSM program, the vast majority of which control only cooling (AC) operations, as previously discussed. This analysis estimates that approximately 1.4M customers with HPs are not participating in a DSM program. Combined enrollment for the Power Manager, Energy Wise Home and BYOT programs is approximately 455,000 customers, yielding roughly 2 kW per condenser per participant based on 910 MW of AC and HP capacity, as defined in Table 9.

[25] EM&V Report for the EnergyWise Home Program, Summer 2016. Navigant, June 5, 2017. Table 1. Estimated Program Impacts

[26] EM&V Report for the EnergyWise Home Demand Response Program, Winter PY2016/2017. Navigant, July 6, 2017. Table 3. Average Demand Reduction Impact by Technology

Table 10. Residential DSM Population Participation

System	Populations			Total Program participants				Total Program HP participants	
	Residential Customers	RASS % HP as Primary Heat System	Estimated Total HP Customers	Power Manager Customers	Energy Wise Customers	Current BYOT Customers	Total Customers	Estimated Total HP Parts	Estimated Total HP Non-Parts
NC									
DEC	1,719,715	41%	708,707	181,870		10,302	192,172	79,195	629,511
DEP	1,203,058	51%	611,829		183,903	4,877	188,780	96,006	515,823
SC									
DEC	495,483	46%	227,267	57,830			57,830	26,525	200,742
DEP	136,802	63%	85,756		15,003		15,003	9,405	76,352
Total	3,555,058	46%	1,633,559	239,700	198,906	15,179	453,785	211,132	1,422,427

Small & Medium C&I DSM Capacity

We considered the DSM capacity in the small and medium C&I sector to be defined primarily by the DEP Small Business EE/DR (SB-EEDR) program. Based on this definition of DSM capacity, Table 11 presents a snapshot of the Small Business EE/DR program (SB-EEDR) which yields approximately 2 MW from controls electric space heating.

Table 11. Small Business EE/DR Program Snapshot

Utility	Rider/Rate	Winter (MW)	% Winter DSM	Summer (MW)	% Summer DSM	kW Threshold
DEP	SB-EEDR	2	0%	11	1%	NA

Large C&I DSM Capacity

Table 12 provides the snapshot values for large C&I DSM programs defined in Table 5, with additional information on kW thresholds required for participating in each program. The following section discusses various aspects of programs funded through various legacy rate base and legacy pricing structures and DSM riders.

Table 12. Large C&I DSM Snapshot

Utility	Rider/Rate Funding Source		Winter (MW)	% Winter DSM	Summer (MW)	% Summer DSM	kW Threshold
DEP	LLC	Legacy Rate Base	72	10%	111	7%	>1,000
	68	Legacy Rate Base	0	0%	0	0%	>1,000
	IPS	Legacy Rate Base	4	1%	7	0%	>1,000
	57	Legacy Rate Base	16	2%	23	1%	>1,000
	NFS	Legacy Rate Base	7	1%	7	0%	>1,000
	LGS-CUR-TOU	Legacy Rate Base	67	10%	81	5%	>1,000
	LGS-RTP Load Response	Legacy Pricing	50	7%	30	2%	>1,000
	DRA	DSM Rider	15	2%	27	2%	>50
DEC	IS	Legacy Rate Base	117	17%	132	8%	>1,000

	SG	Legacy Rate Base	10	1%	11	1%	>1,000
	PowerShare	DSM Rider	317	46%	338	20%	>100

Legacy Programs

Legacy programs are 52% of our snapshot large C&I winter DSM capacity defined in Table 13. For DEP, legacy programs account for 94% of 231 MW snapshot capacity, compared to 29% for DEC. Legacy programs share many of the following attributes:

- These programs are mature, and the kW threshold generally limits program participation to large C&I customers.
- These programs do not require opts-in to the EE/DSM rider.
- DEC legacy programs are closed, and participation is limited to customers participating before PowerShare.
- These programs are called infrequently and only for grid emergencies, not economic dispatch.
- They are appropriate as an occasional resource but providing relief during periods when events need to be called over multiple consecutive days, such as polar vortex events, can strain customers and may result in diminishing results. In these situations, it's likely that some subscribers would drop the program or simply absorb the penalty rather than disrupt, depending on the penalties applied for each program.
- During the winter, programs usually call events the day before, but overnight developments can result in shorter term notification, no less than ½ hour. For winter events that are called on short notice, contacts may not be on site, or there isn't time to organize an operational response prior to winter system peaks occurring between 7 a.m. and 8 a.m. In contrast, summer events are more typically called day of because this provides customers time to mobilize and participate in an event.
- Several of the riders shown in Table 12 are closed and load growth in target markets has been stagnant. Many of the programs target large industrial customers, and this load is decreasing; for example, the MPS forecasts the industrial sector to decrease by 6% in NC[27] and 11% in SC[28] by 2044. This decrease will impact programs differently, such as the Interruptible Power Service Rider (IS) that is comprised mostly of textile mills.

DSM Rider Programs

Beginning in 2009, Duke began implementing the DEC PowerShare (PS) and DEP Demand Response Automation (DRA) programs, both of which are funded through the DSM component of the EE rider and account 48% of the snapshot large C&I winter capacity shown in Table 12. The EE rider is unique to each state and utility.

Based on data provided by Duke for July 2020, Table 13 shows 164 customers participating in PS, with 328 MW of winter snapshot capacity. Winter capacity is 20 MW lower than summer, all of which is associated with process loads. The average yield is 2.0 MW per PS participant. Table 13 also shows 88 DRA customers participating with 15 MW of winter snapshot capacity compared to 27 MW summer. The average winter MW yield is 0.2 MW per DRA participant. DRA is the only rider funded program that

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[27] Duke Energy North Carolina EE and DSM Market Potential Study. Nexant, April 2020. Figure 3-13: DEC Electricity Sales Forecast by Sector for 2020 - 2044

[28] Duke Energy South Carolina EE and DSM Market Potential Study. Nexant, April 2020. Figure 3-17: DEC Electricity Sales Forecast by Sector for 2020 - 2044

shows impacts from building systems, such as HVAC and lighting, and all HVAC and lighting reduction is attributable to a single large retailer with multiple sites enrolled and is summer only.

Table 13. Summary of PowerShare and DRA Capacity by Load Reduction Source

Load Reduction Source	Participants	Capacity (MW@mtr) Summer	Capacity (MW@mtr) Winter	Ave Winter MW / Participant
PowerShare				
Generator	55	67	67	1.2
Process	109	281	261	2.4
HVAC/Lighting	0	0	0	0.0
PowerShare Total	164	348	328	2.0
DRA				
Generator	41	17	12	0.3
Process	36	9	3	0.1
HVAC/Lighting	11	0.7	0.0	0.0
DRA Total	88	27	15	0.2
Combined				
Generator	96	85	79	0.8
Process	145	290	264	1.8
HVAC/Lighting	11	0.7	0.0	0.0
Combined Total	252	376	343	1.4

Table 14 provides a distribution of capacity by program and load reduction source showing 80% of PS capacity is associated with process activity, and 20% through customer sited generators. Table 14 also shows PS accounting for 96% of winter reduction.

Table 14. PowerShare and DRA Capacity Allocation by Load Reduction Source

Load Reduction Source	OPCO - Program DEC - PS	OPCO - Program DEP - DRA	System DEC - PS	System DEP - DRA
Generator	20%	80%	20%	3%
Process	80%	20%	76%	1%
HVAC/Lighting	0%	0%	0%	0%
Total	100%	100%	96%	4%

Over the past 6 years, both PS and DRA have experienced attrition from EPA and Non-EPA related changes in the market. Table 15 summarizes trends over 6 years, from 2015 to 2020. During this period PS has lost a net of 31 MW and 63 customers, with 41% of ME attrition related to EPA activity and directives. DRA gained a net of 7 MW and 31 customers. EPA attrition accounted for 72% of DRA lost capacity during this time. Much of the EPA attrition is related to loss of backup generation capacity at water treatment facilities.

Table 15. Summary of PS and DRA Attrition, 2015 to 2020

Measure	**MW**		**Customers**	
Program	PS	DRA	PS	DRA
New Enrollments	110	17	47	49
Total Attrition	(141)	(10)	(110)	(14)

Net 6-year Attrition	(31)	7	(63)	35
EPA Attrition	41%	72%	45%	71%
Non-EPA Related Attrition and True Up	59%	28%	55%	29%

Summary of DSM Rider Opt-out

Table 16 shows a summary of DEP opt out statistics by rate, indicating near 100% opt-out for larger customers. Table 17 shows our analysis of opt-out by C&I customers for both DEC and DEP, showing 50% C&I opt-out based on C&I sales.[29,30] As Duke's DSM capability is currently configured, growth in overall DSM capability falls primarily on residential and small to medium size commercial customers because legacy programs have limited growth potential and DSM rider opt-out occurs primarily among large C&I customers.

Table 16. DEP Opt-out by Rate Class

Rate Class	Opt Out	Accounts	% Opt-out
SGS	4,413	183,637	2%
MGS	684	19,713	3%
LGS	212	214	99%
LGS-RTP	90	90	100%

Table 17. Summary of Opt-out by Utility

Utility	DEC	DEP	Total
Total C&I GWh	33,868	25,948	59,815
C&I GWh Opt-out	18,851	10,967	29,818
% C&I GWh Opt-out	56%	42%	50%
% Total GWH Opt-out	33%	25%	30%

[29] For 2019 based on Duke Energy Carolinas, LLCDSM/EE Cost Recovery Rider 12 Docket Number E-7 Sub 1230
[30] For 2019 based on Duke Energy Carolinas, LLCDSM/EE Cost Recovery Rider 12 Docket Number E-7 Sub 1230

4. Residential Market and Solutions

Rate Definitions

Table 18 provides a summary of rates we reviewed to assess winter peak impacts from the residential sector. The table shows the distribution between TOU and flat rates, where flat rates are defined as those rates that are not time differentiated but may include a seasonal adjustment. Virtually all DEC residential load is on flat rates with 56% of customers subscribing to the all-electric rate, RE, which requires customers to have both electric space and hot water heating, while 43% are on the RS rate, which is designed for dual fuel customers. Less than 1% are on the DEC residential TOU rate, RT. Approximately 97% of DEP customers on a flat rate, Res-58, which applies to electric or dual fuel homes. Approximately 3% of DEP residential customers are on TOU pilot rates, R-TOU-58 or R-TOUD-58. Overall, approximately 99% of residential customers are on flat rates.

Table 18. Residential Rates Summary

System	Schedule	Tier Type	On Peak	Winter	Study Peak Day MW	% Utility Sector Demand	% System Load
DEC	RS	None	None	Nov – June	3,306	43%	25.4%
	RE	Tiered kWh	None	Nov – June	4,297	56%	33.0%
	RT	On/Off kWh	7:00 a – 12:00 n	Oct – May	15	0.2%	0.1%
DEP	RES-58	None	None	Nov – June	5,237	97%	40.3%
	R-TOU-58	On/Part/Off kWh	6:00 a - 9:00 a	Sept - Mar	146	3%	1.1%
	R-TOUD-58	On/Off kWh On kW	6:00 a - 1:00 p	Sept - Mar			

Peak Load Profile

DEC

As previously defined, our study peak day occurred on January 5th, 2018 with the DEC RE rate hitting approximately 4,300 MW between 7:00 and 8:00 a.m. as shown in Figure 25. Also shown in Figure 25 is a morning peak of around 200 MW for the RS rate. The RS rate peak is caused by household appliances, but also includes fan motor supporting natural gas furnaces. A typical fan motor will use about 400 watts and these loads would be available for reduction in set-back thermostat solutions, including those already installed for summer AC programs, though we did not calculate this potential.

Figure 29. DEC 2018 Res Demand Profile by Rate Schedule – Study Peak Day

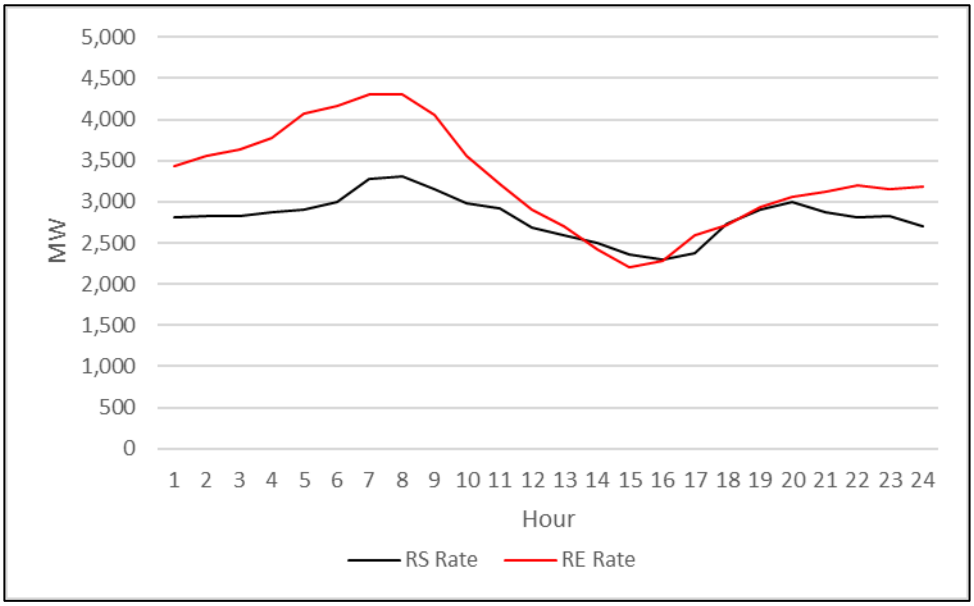


Figure 26 is the average of six winter peak days in 2018 for the RS and RE rates and shows the same profile as Figure 25, though the average morning and evening peaks are lower for each rate than the study peak day. The difference between study peak day and average winter peak day is about 900 MW, or study peak day demand is about 26% higher than the average winter peak day. This is an indicator of sensitivity to weather events in the residential sector though we did not correlate the difference in demand due to any outdoor temperature trends.

Figure 30. DEC 2018 Res Demand Profile by Rate Schedule - Average Winter Peak Day

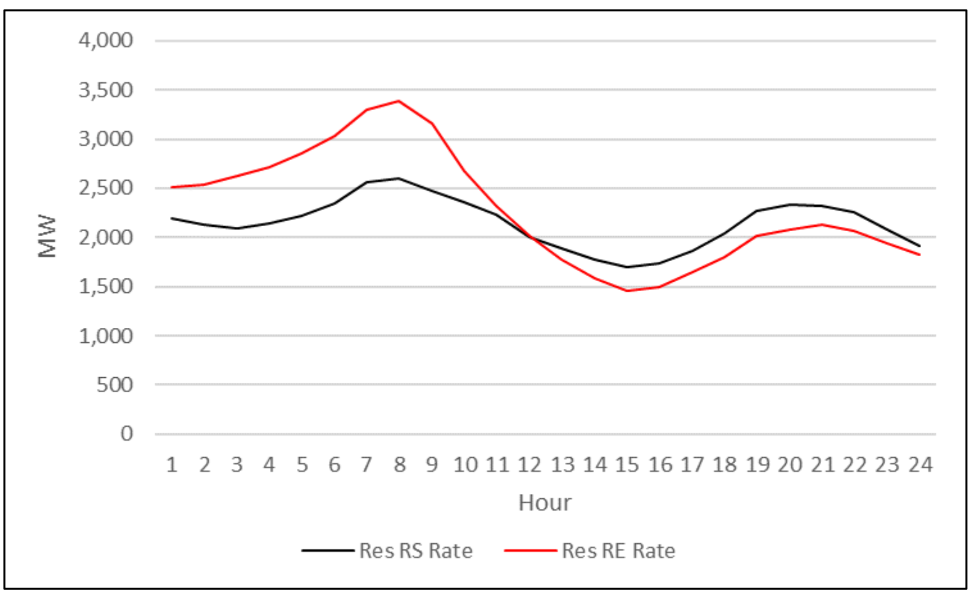


Figure 27 compares the TOU rate, RT, to the RT and RS rates, showing the average winter peak day demand profile over a 24-hour period for all three rates. We observe that the RT rate profile more closely aligns with the RE rate, with some slight shifts, but participation in the RT rate is very small and the distribution of all electric and natural gas homes within this rate is unknown and so no definitive conclusions about TOU impacts on behavior can be drawn.

Figure 31. DEC 2018 Res Demand Profile by Rate Schedule - Average Winter Peak Day

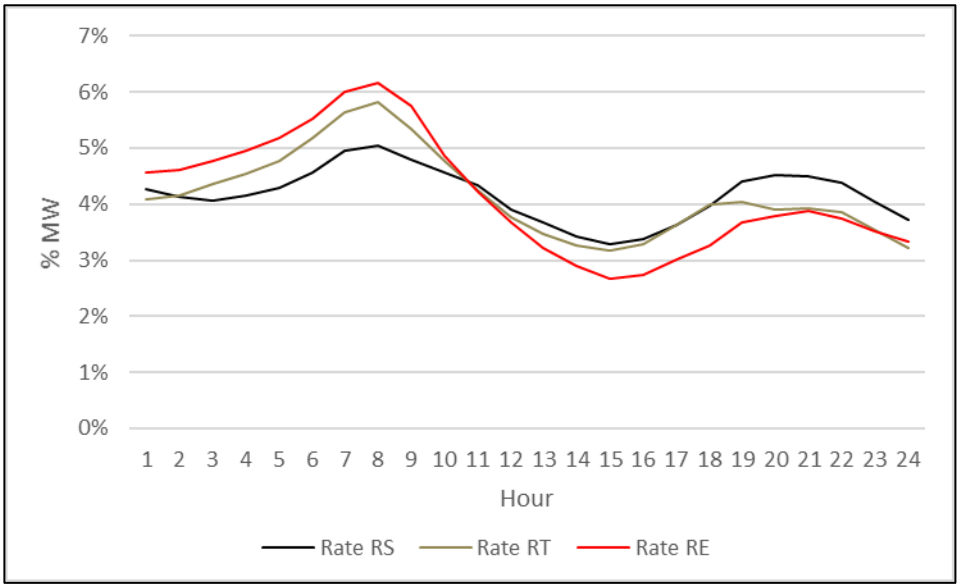


Figure 28 compares the average winter and summer peak for the RE rate for the 6 winter and 4 summer peak days previously defined at Table 3. On average, winter peak exceeds summer peak by about 1,000 MW. Because household appliances and hot water usage is generally consistent throughout the year, we estimate that the difference in morning demand between summer and winter is about 2,500 MW in electric heating load. Also, because a heat pump condenser consumes roughly the same electricity in heating or cooling modes[31], the increased demand of approximately 1,000 MW in the winter above the summer peak may be attributed to electric resistance heating sources other than just heat pump condensers, including:

- Supplemental heat strips on HP heating system that adds incremental load to the HP condenser
- Electric wall furnaces
- Electric baseboard heaters
- Small supplemental plug-in heaters

Note that this analysis focused on average winter peak day, however the study peak day saw 26% increased usage as discussed at Figure 26, and we would expect the increased demand during cold weather events to be distributed proportionately across heat pump condensers and other space heating devices.

[31] Excluding supplemental heat strips on HP heating systems

Figure 32. DEC 2018 RE Rate Demand Profile - Average Season Peak Day

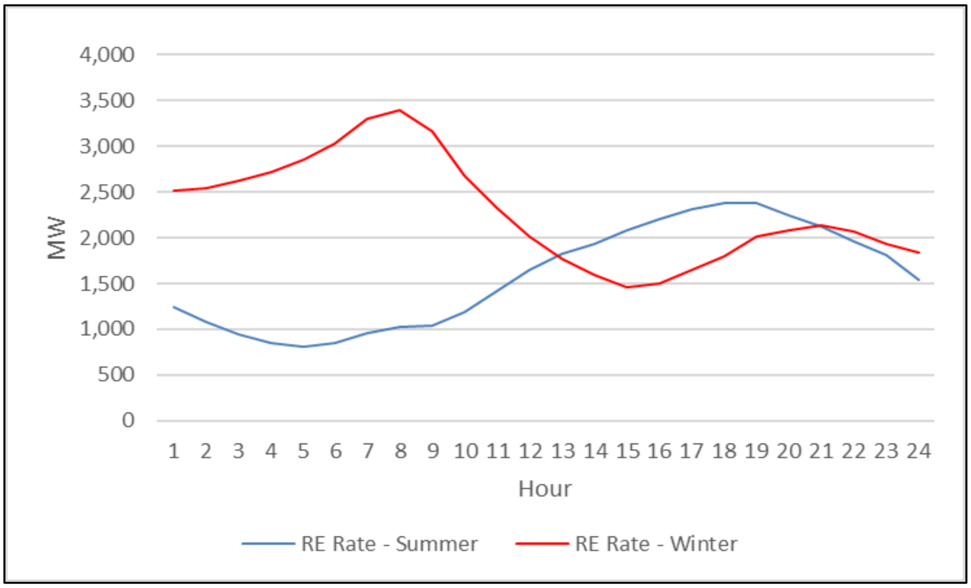
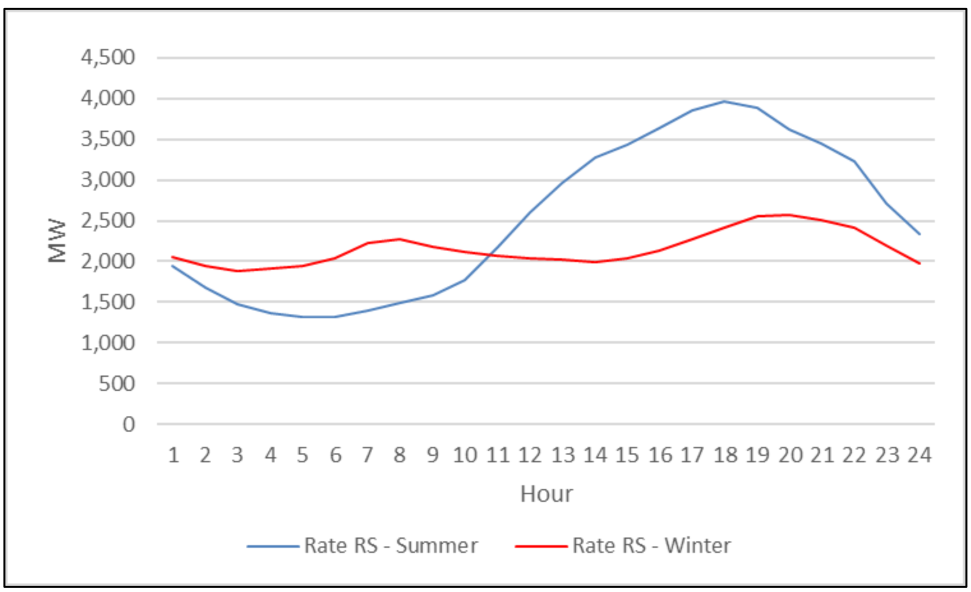


Figure 29 ccompares winter and summer peak for the RS rate for these same 6 winter and 4 summer peak days illustrating the considerable summer evening peak associated with AC demand. We expect that any thermostat solution targeted at winter peak will have benefits for summer AC demand.

Figure 33. DEC 2018 RS Demand Profile - Average Season Peak Day



DEP

Figure 30 compares the demand profiles for the DEP Res-58 (flat rate) and the R-25-TOU rate, indexed to show the percent of total average daily consumption.[32] While there appears to be some slight difference in usage patterns such that TOU subscribers have higher usage earlier in the morning, indicating a shift, and lower evening peaks, the low TOU rate (about 3% residential load) precludes any definitive statement about TOU impact on behavior (i.e., load shifting).

[32] We present this as a demand profile because R-TOU-58 accounts for only 2.8% of DEP residential load.

Figure 34. DEP 2018 Res Demand Profile by Rate Schedule - Average Winter Peak Day

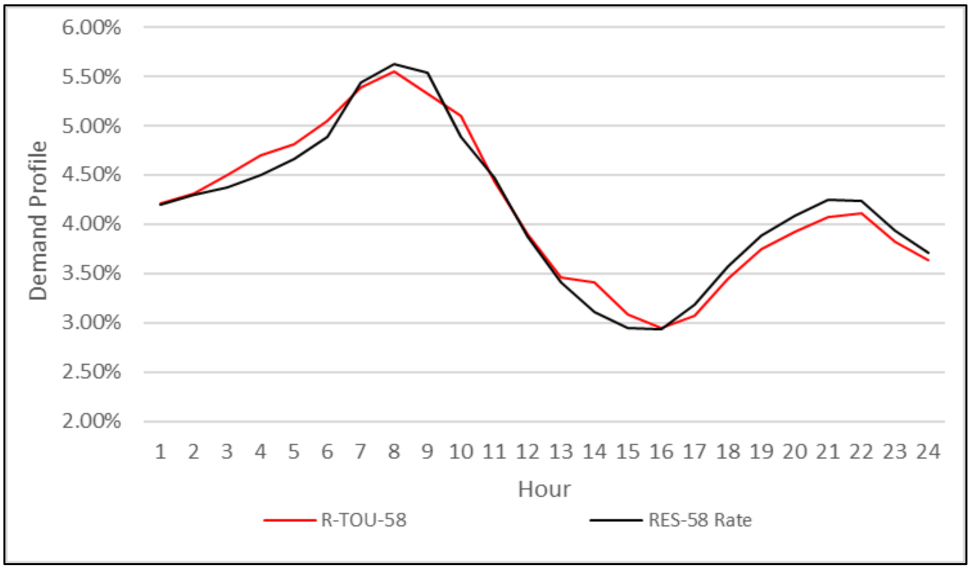
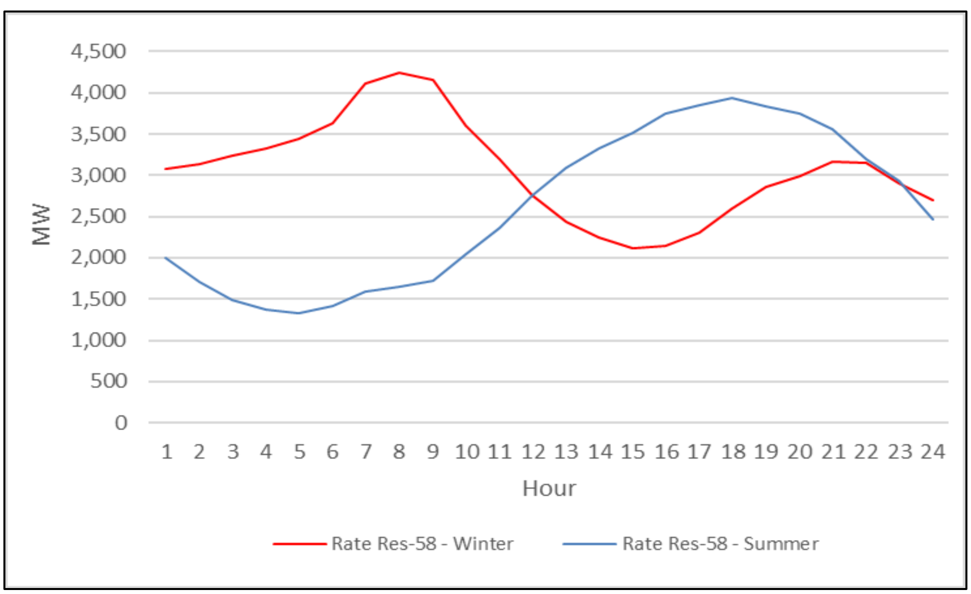


Figure 31 compares average winter and summer peak for the DEP R-TOU-58, and we do see a slight increase in R-TOU-58 average winter peak demand compared to summer, likely because this rate blends homes heated with electric heat and natural gas. Based on the demand differential observed between the DEC RE and RS rates discussed in Figure 26, and adjusting for differences in residential customer base between the 2 utilities, we expect that about 1,500 MW of Res-58 morning winter demand is attributable to homes with electric heating. Using the same logic discussed for DEC at Figure 28, we expect about 900 MW is associated with heat pump condensers and 600 MW of this is attributable to other resistance heating systems, such as 1) supplemental heat strips on HP heating system that adds incremental load to the HP condenser, 2) electric wall furnaces, 3) electric baseboard heaters, and 4) small supplemental plug-in heaters. This analysis was completed for the average winter peak day, but demand would be higher during colder weather events, as shown in Figure 28.

Figure 35. DEP 2018 Res-58 Demand Profile - Average Season Peak Day



Market Characteristics

We used various datasets to characterize the residential market, including Duke and EIA data indicating 3,558,000 total residential customers, with 2,923,000 in NC and 635,000 in SC. To understand the characteristics of customers applicable to winter peak solutions, we used data from the American Community Survey (ACS) to define the distribution of customers across various dwelling types, and data from the 2019 RASS to further define the population of dwellings that have heat pump space heating and electric HWH. As shown in Table 19, we estimate approximately 1,053,000 dwellings are heated with heat pumps, and 2,526,000 dwellings have electric hot water heating.

Table 19. Residential Dwelling Counts and Distribution of Heat Pumps and Electric Hot Water Heating

	Total Dwelling			HP Dwellings			Electric HWH Dwellings		
Dwelling Type	System	DEC	DEP	System	DEC	DEP	System	DEC	DEP
1-unit, detached	2,303,273	1,431,618	871,655	1,036,473	644,228	392,245	1,635,324	1,016,449	618,875
1-unit, attached	139,570	85,879	53,691	55,828	34,352	21,477	99,095	60,974	38,121
2 units	73,727	45,877	27,850	36,864	22,938	13,925	52,346	32,573	19,774
3 or 4 units	98,612	61,461	37,151	41,417	25,814	15,603	70,015	43,637	26,377
10 to 19 units	145,313	89,698	55,615	72,657	44,849	27,808	103,173	63,686	39,487
5 to 9 units	152,874	95,185	57,688	76,437	47,593	28,844	108,540	67,582	40,959
20 or more units	159,809	100,058	59,752	79,905	50,029	29,876	113,465	71,041	42,424
Mobile home	484,955	305,350	179,605	290,973	183,210	107,763	344,318	216,799	127,520
Total	3,558,134	2,215,126	1,343,008	1,690,553	1,053,012	637,541	2,526,275	1,572,739	953,536

We also used the ACS and 2019 RASS data to assess the population of renters and owners by dwelling type. As shown in Table 20, 65% of customers are owners and 35% are renters, and 16% of dwellings are multifamily (defined here as 2 or more units). Virtually all multifamily dwellings are renters. About 70% of all multifamily dwellings are large apartment building (5 or more units).

Table 20. Residential Occupant Type

Dwelling Type	% Dwellings	% Owners	% Renters
Single-family detached house	68%	87%	13%
Single-family attached (e.g., townhomes)	7%	72%	28%
Duplex two-family building	2%	14%	86%
Apartment building (3-4 units)	3%	0%	100%
Large apartment building (5 or more units)	11%	1%	99%
Mobile home	6%	71%	29%
Condominium	3%	65%	35%

We also used the ACS to estimate that 27% of NC and SC customer are low-income. Figure shows how these are distributed by income cohort as a percent of FPL. From previous work completed by Tierra, Figure shows that the lower a customer's income, the more likely they are to live in multifamily dwellings. We did not adjust our solutions set potential based on income cohort, but would note that implementing the solution set should consider the following with regards to low-income customers:

- We assume that multifamily dwellings will have higher saturation of baseboard heaters and electric wall furnaces and we expect that these systems make up a significant percentage of resistance heat load not related to HPs as discussed at Figure 28.

- Low-income retrofit programs (i.e., weatherization) typically require access to dwellings to complete their work, and this offers an opportunity to install thermostat or other DSM solutions. We note that access to the interior of customer homes was cited in the IRP as a barrier to implementing DSM measures.
- Low-income retrofits of multifamily dwellings offer an opportunity to access multiple dwellings in a single visit because the activity is often coordinated through a single building owner contact, thus limited customer acquisition and logistical costs.
- The solution set includes economic benefits for all customers, but these may have a more material impact for low-income customers.

Figure 36. Distribution of Low-income Residents by Income Cohort

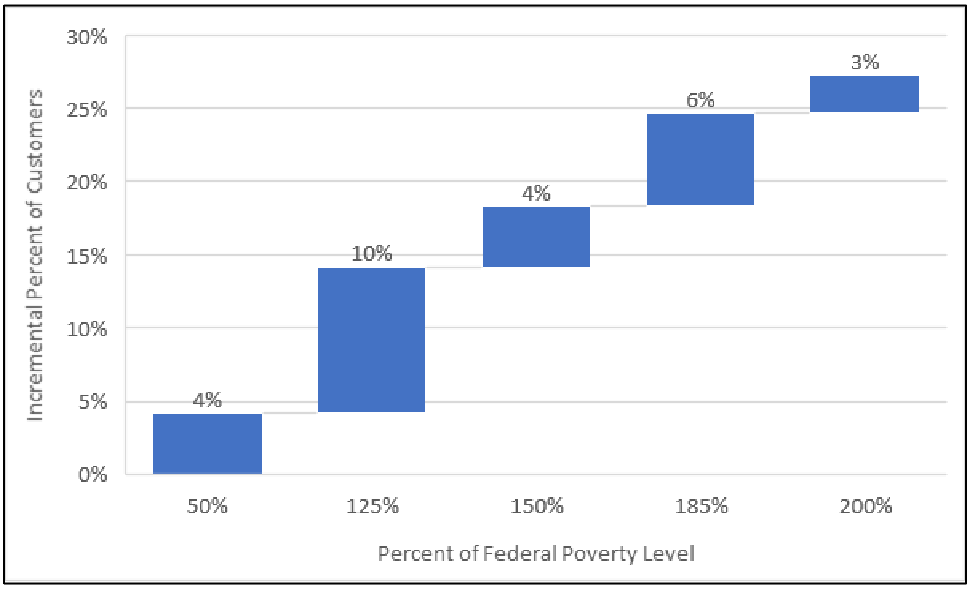
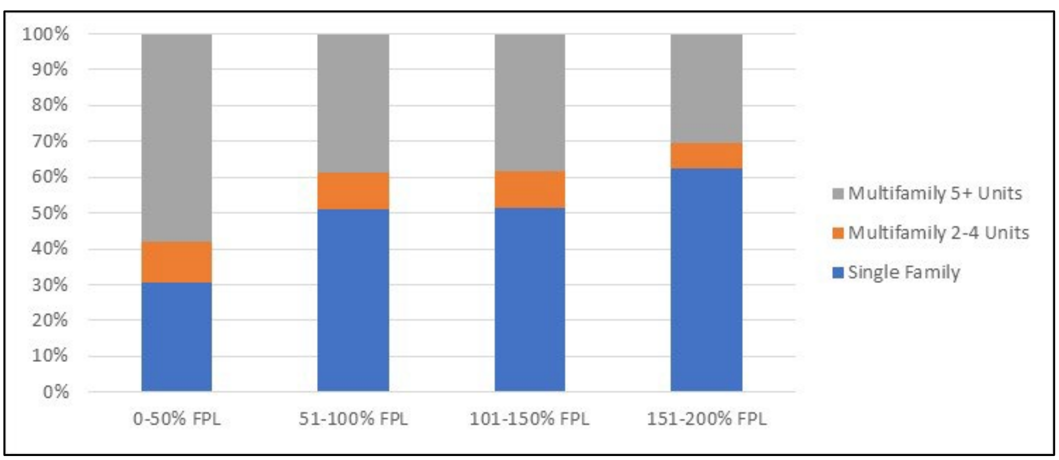


Figure 37. Residential Dwelling Types by FPL Income Cohort



The following sections discuss the market and technical characteristics of space heating, thermostats, and electric hot water heating.

Space Heating

Based on data from the 2019 RASS, Table 21 shows that electric space heaters account for 54% of all residential primary heating systems, including 46% stand-alone heat pumps and 8% resistance heaters, which would include primarily baseboard heaters and electric wall furnaces. Table 22 shows that the distribution of heating system types is constant across owner and renter resident types, except for resistance heating. Renters account for 62% of all resistance heating installations.

Table 21. Primary Space Heat System Type by Utility

System Type	DEP	DEC	System
Stand-alone Gas Furnace	34%	44%	40%
Heat pump with a Gas Back-up	5%	7%	6%
Stand-alone Heat Pump	52%	42%	46%
Electric Resistance	9%	8%	8%

Table 22. Space Heat System Type by Resident Type

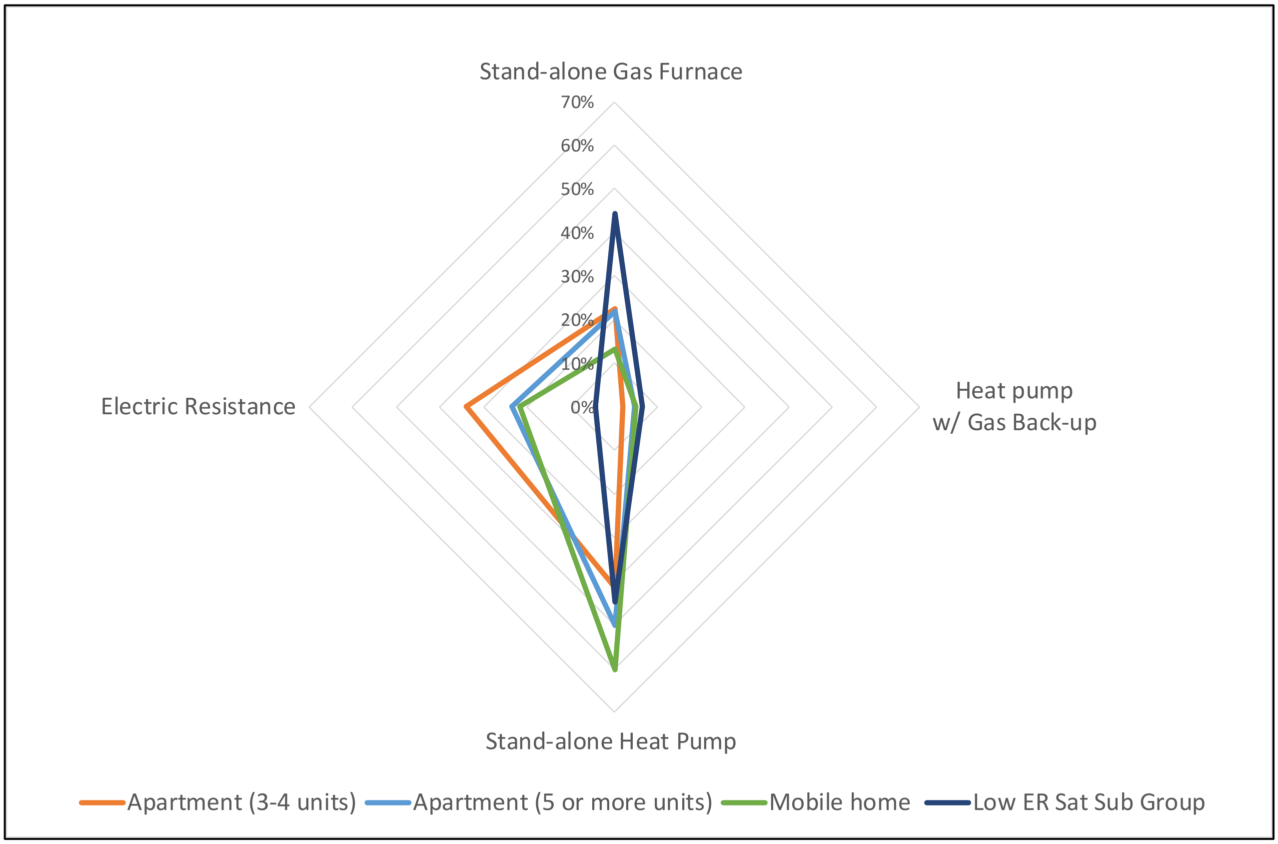
Resident Type	Stand-alone Gas Furnace	Heat Pump with Gas Back-up	Stand-alone Heat Pump	Electric Resistance	% Total Systems
Owner	79%	76%	74%	38%	73%
Renter	21%	24%	26%	62%	27%
Total	100%	100%	100%	100%	100%

Table 23 shows that single family (attached and detached), duplexes and condominiums have resistance heater saturations at or less than 5%, while saturations are higher for mobile homes (22%), apartments with 3 of 5+ units (24%), and apartments with 3 of 4 units (34%), as further illustrated in Figure 35. We assume that most electric wall furnaces will be controlled by a thermostat while baseboard heaters are typically controlled at the room level through a simple on/off switch, though the 2019 RASS data did not provide a disaggregation between baseboard heaters and electric wall furnaces or the types of controls being used. As discussed at Figure 34 we expect that many of the systems installed in multifamily dwellings will be occupied by low-income residents.

Table 23. Space Heat System Type Distribution by Dwelling Type

	Low Electric Resistance Saturation				High Electric Resistance Saturation		
System Type	Single-family Detached	Single-family Attached	Duplex	Condo	Apartment (3-4 units)	Apartment (5 or more units)	Mobile home
Stand-alone Gas Furnace	45%	48%	40%	33%	23%	22%	13%
Heat pump w/ Gas Back-up	6%	7%	7%	6%	2%	5%	5%
Stand-alone Heat Pump	45%	40%	50%	57%	42%	50%	60%
Electric Resistance	4%	5%	3%	4%	34%	24%	22%

Figure 38. Distribution of Electric Resistance Heating by Dwelling Type



We completed a modelling analysis using NREL's Building Energy Optimization Tool (BEopt[33]) to disaggregate residential heat pump loads during peak usage period. Figure 37, Figure 38, and Figure 39 show 24-hour load shapes for single family high and medium users, and multifamily dwellings, respectively. In all dwelling types the load from heating accounts for approximately 80% of morning demand and is driven by three subsystems including 1) the heat pump condenser, which makes up the bulk of demand, 2) supplemental heat strips that provide additional heating during cold periods, and 3) the ventilation fan that distributes warm air.

Winter peaks are primarily driven by residential electric space heating loads and these loads can be difficult to predict because of the way residential heat pumps work during their heating cycle. Heat pumps provide both space cooling and space heating and the condensers work the same in either the heating or cooling mode. However, most heat pumps systems also have supplemental resistance heaters that provide additional heating capacity when a dwelling requires more heat than the condenser can provide. This supplemental resistance heating can increase total heat pump demand by a factor of 3 (e.g., increase from 4 kW to 12 kW for a single home). The In short, the same home equipped with a heat pump might have three times the HVAC load in winter as it does during the summer, and while this disparity makes winter peaks harder to predict it is also shorter in duration than summer peak and can be effectively controlled through programmatic solutions. Figure 37, Figure 38, and Figure 39 are based on average loads for a population of heat pumps and do not fully capture these short duration events when many supplemental heat pump resistance heating elements may be active.

[33] At https://beopt.nrel.gov/home

Figure 39. Single Family Peak Load Profile - High User

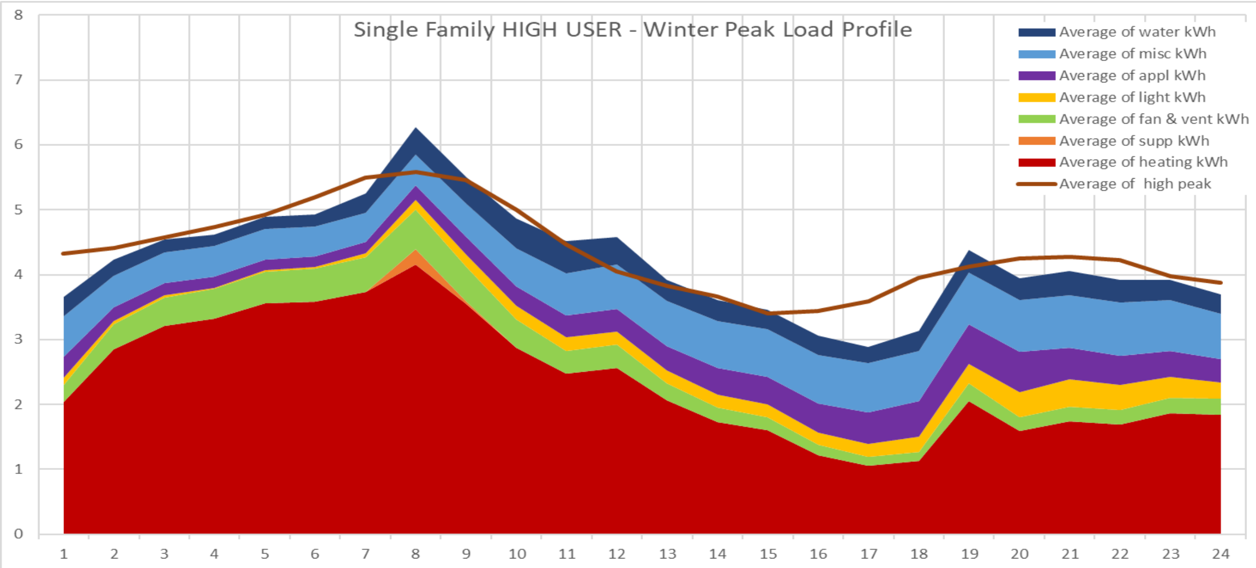


Figure 40. Single Family Peak Load Profile – Medium User

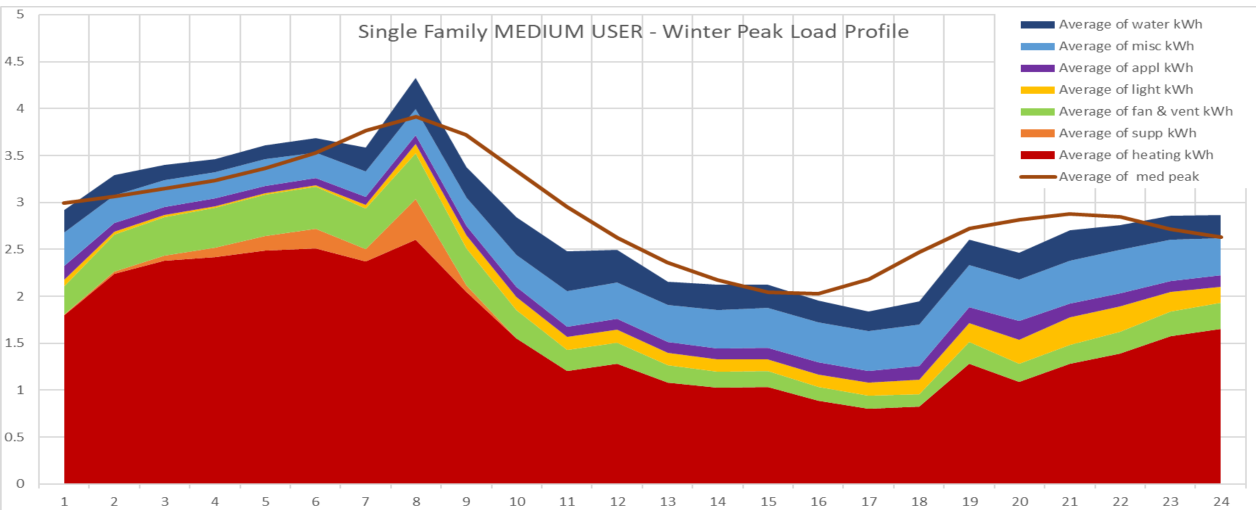
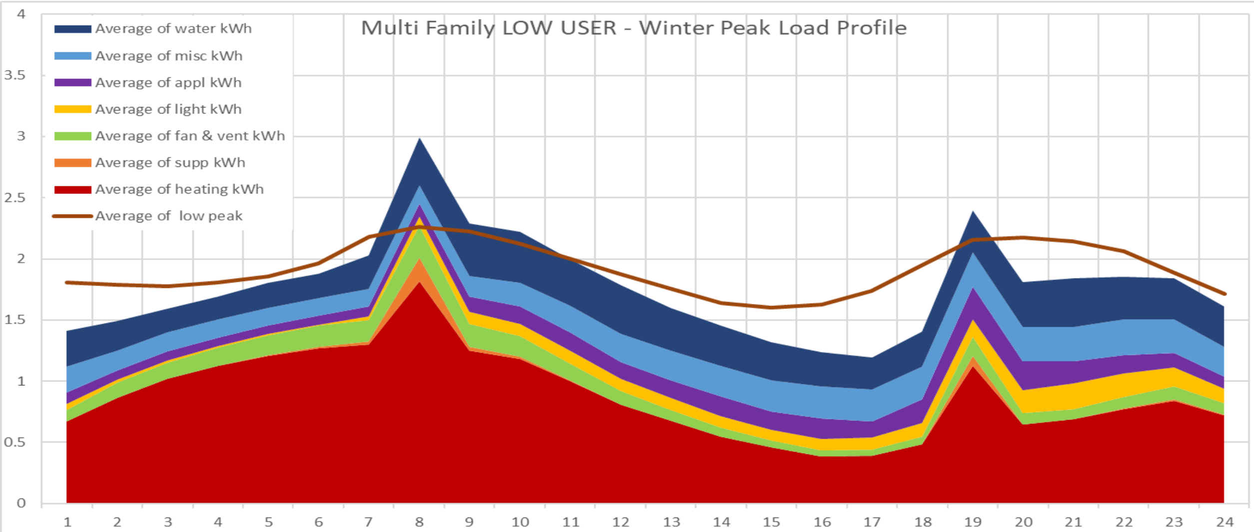
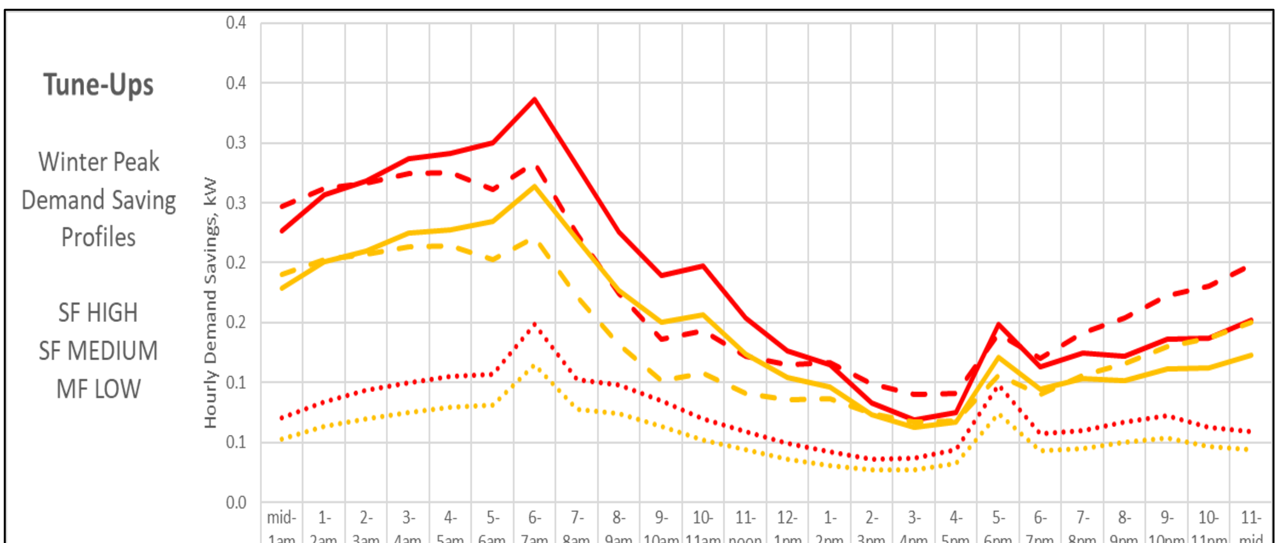


Figure 41. Multi-Family Peak Load Profile – Low User



In addition to disaggregating heat pump load, we used BEopt to estimate savings potential from tuning-up heat pumps to run more efficiently in the winter and to better control when the supplement heat strips are activated. The premise underlying tune-ups is that contractors often set controls on the supplemental heat strip to activate unnecessarily. Figure 39 provides our estimate of savings for various heat pump performance factors and indicates that demand savings at 7:00 a.m. ranges between 0.12 to 0.35 kW per system, depending on heat pump system efficiency, dwelling type and occupant usage patterns.

Figure 42. Estimate of Winter Heat Pump Tune-up Savings



	mid-1am	1-2am	2-3am	3-4am	4-5am	5-6am	6-7am	7-8am	8-9am	9-10am	10-11am	11-noon	12-1pm	1-2pm	2-3pm	3-4pm	4-5pm	5-6pm	6-7pm	7-8pm	8-9pm	9-10pm	10-11pm	11-mid
High - HSPF 6.2 - Tune-Up	0.23	0.26	0.27	0.29	0.29	0.30	0.34	0.28	0.23	0.19	0.20	0.15	0.13	0.11	0.08	0.07	0.07	0.15	0.11	0.12	0.12	0.14	0.14	0.15
Med - HSPF 6.2 - Tune-Up	0.25	0.26	0.27	0.27	0.28	0.26	0.28	0.22	0.17	0.14	0.14	0.12	0.12	0.12	0.10	0.09	0.09	0.14	0.12	0.14	0.15	0.17	0.18	0.20
Low - HSPF 6.2 - Tune-Up	0.07	0.08	0.09	0.10	0.10	0.11	0.15	0.10	0.10	0.08	0.07	0.06	0.05	0.04	0.04	0.04	0.04	0.10	0.06	0.06	0.07	0.07	0.06	0.06
High - HSPF 7.7 - Tune-Up	0.18	0.20	0.21	0.22	0.23	0.23	0.26	0.22	0.18	0.15	0.16	0.12	0.10	0.10	0.07	0.06	0.07	0.12	0.09	0.10	0.10	0.11	0.11	0.12
Med - HSPF 7.7 - Tune-Up	0.19	0.20	0.21	0.21	0.21	0.20	0.22	0.17	0.13	0.10	0.11	0.09	0.09	0.09	0.07	0.07	0.07	0.11	0.09	0.11	0.12	0.13	0.14	0.15
Low - HSPF 7.7 - Tune-Up	0.05	0.06	0.07	0.08	0.08	0.08	0.12	0.08	0.07	0.06	0.05	0.04	0.04	0.03	0.03	0.03	0.03	0.07	0.04	0.04	0.05	0.05	0.05	0.04

In order to assess the viability of forecasted impacts for heating solutions, we wanted to get a sense of the technical demand related to heat pump space heating, where technical demand is defined as the MW that would result if all heat pumps were operating at the same time. Using the analysis completed by Proctor Engineering, Table 25 provides our estimate of technical system demand of 7,900 MW based on the following assumptions:

- 47% of all heating systems are heat pumps and also represent 47% of all residential dwelling space (sq.ft.).
- Approximately 2.7B sq. ft. of residential dwellings in Duke NC and SC territories are heated by heat pumps.
- Heat pumps represent about 80% of electric home demand during peak load periods where appliances and electric hot water heating are also operating coincident with the heat pump.
- Heat pumps use approximately 4.6 kW per dwelling, or about 2.9 watts / sq. ft., when considering average house sizes, built environment heat pump efficiency, and demand from system components on high, medium, and low users as defined in Table 24.

Table 24. Dwelling Level Heat Pump Technical Demand Components (kW) by Use Category

Component	High	Med	Low	Ave
Heat Strip	2.2	1.4	1.0	1.5
Fan and vent	0.6	0.5	0.3	0.5
Heat Pump	4.0	2.5	1.7	2.7
Total HP	6.8	4.4	3.0	4.6

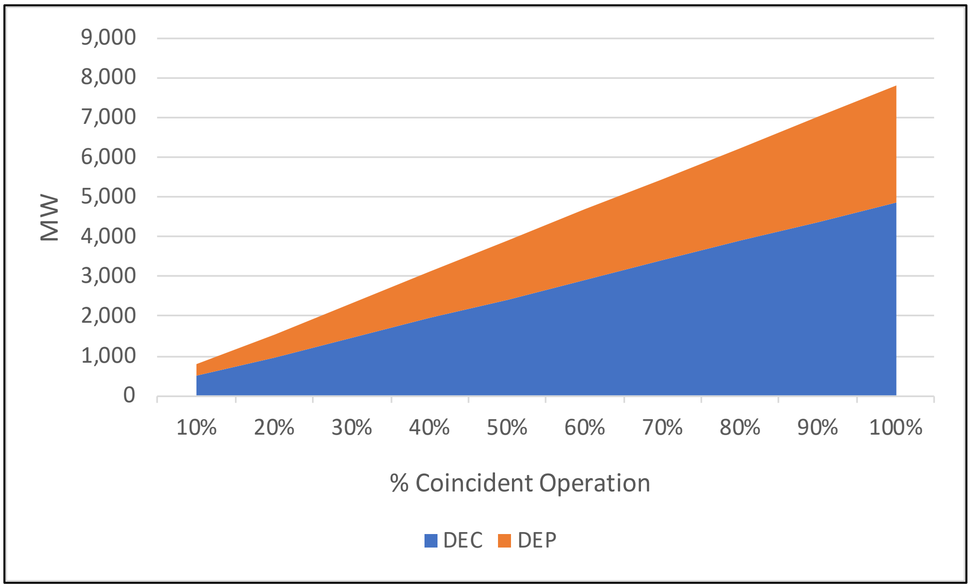
Table 25 shows technical demand from heat pump operation where technical demand is defined a worst-case scenario that assumes all system are operating simultaneously (i.e., 100% coincident operation). Reaching technical demand, is an unlikely event and Figure 40 shows the estimated heat pump loads at various levels of coincident operation. A more reasonable estimate would be around 60% during cold events, which indicates a load of 4,100 MW. At this level, heat pumps would account for 33% of the 12,600 MW of total residential load on our study peak day as discussed at Figure 20. We would expect higher coincidence during periods where residents may not go to work in the morning, such as extreme weather-related shutdowns or shelter -in-place events.

Table 25. Heat Pump Technical Demand

Dwelling Type	System	DEC	DEP
2 units	145	90	55
3 or 4 units	163	101	61
1-unit, attached[34]	232	143	89
10 to 19 units	231	143	88
5 to 9 units	243	151	92
20 or more units	254	159	95
Mobile home	749	472	278
1-unit, detached	5,604	3,483	2,121
Total	7,942	4,944	2,998

[34] This is a 1-unit structure that has one or more walls extending from ground to roof separating it from adjoining structures. In row houses (sometimes called townhouses), double houses, or houses attached to nonresidential structures, each house is a separate, attached structure if the dividing or common wall goes from ground to roof.

Figure 43. System Res Heat Pump Demand at Various Level of Operating Coincidence[35]



Thermostats

Our review of the 2019 RASS shows that overall saturation of Wi-Fi T-stat is 21% but varies by type of heating system as shown in Table 26. Saturation also varies by occupant type, as shown in Table 27 and Figure 41, where only 4% of renters report having a Wi-Fi T-stat versus 22% of owners. This analysis provides a baseline to estimate the population of devices available for thermostat solutions and reinforces the notion that low-income multifamily renters present a viable technology market where thermostat solutions will likely have a more material economic benefit.

Table 26. % of Systems with Wi-Fi T-Stat

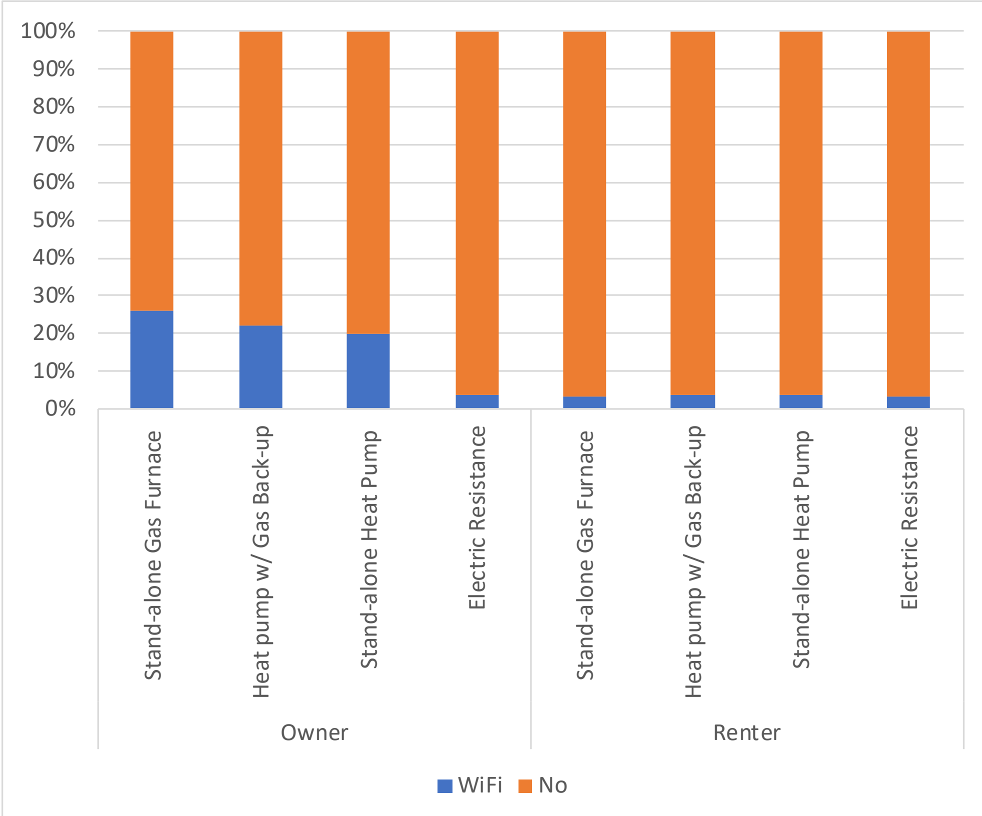
System Type	Wi-Fi
Stand-alone Gas Furnace	29%
Heat pump w/ Gas Back-up	26%
Stand-alone Heat Pump	24%
Electric Resistance	7%

Table 27. Wi-Fi T-Stat Type Saturations by Occupant Type

Occupant Type	Yes	No
Owner	22%	78%
Renter	4%	96%

35 KEY FILE - NC and SC ACS Data housing 2020.06.09

Figure 44. Wi-Fi T-Stat Saturation by Heating System and Occupant Type



Electric Water Heating

Our review of the 2019 RASS indicates that 71% of HWH is electric and that 86% of rental units are electric HWH, vs. 67% for owner occupied dwellings, as shown in Table 28. Table 29 further breaks down water heat fuel by dwelling type, further defining high saturation in the rental market, especially dwellings with 3 or more units. Figure 42 shows the percentage of water heaters by design types, showing that 98% of HWH have a tank (resistance or HP).

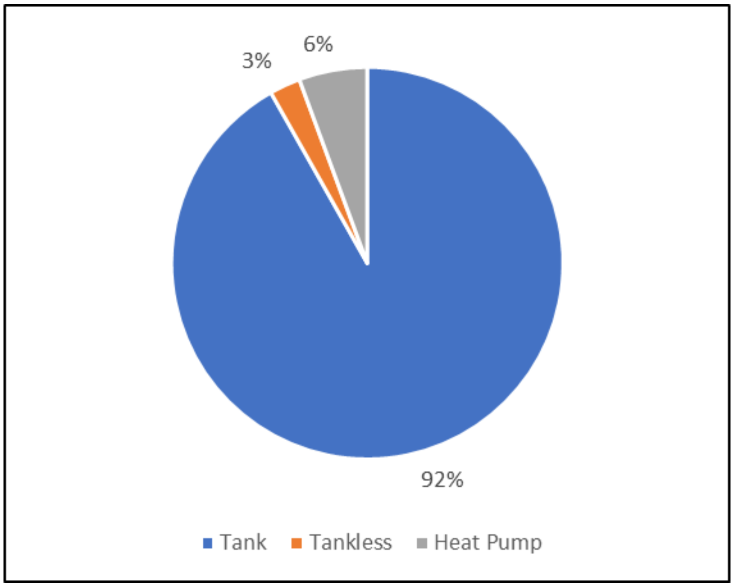
Table 28. Water Heat Fuel Type by Resident Type

Resident Type	Electric	Natural gas	Resident Total
Owner	67%	33%	100%
Renter	86%	14%	100%

Table 29. Water Heat Fuel by Dwelling Type

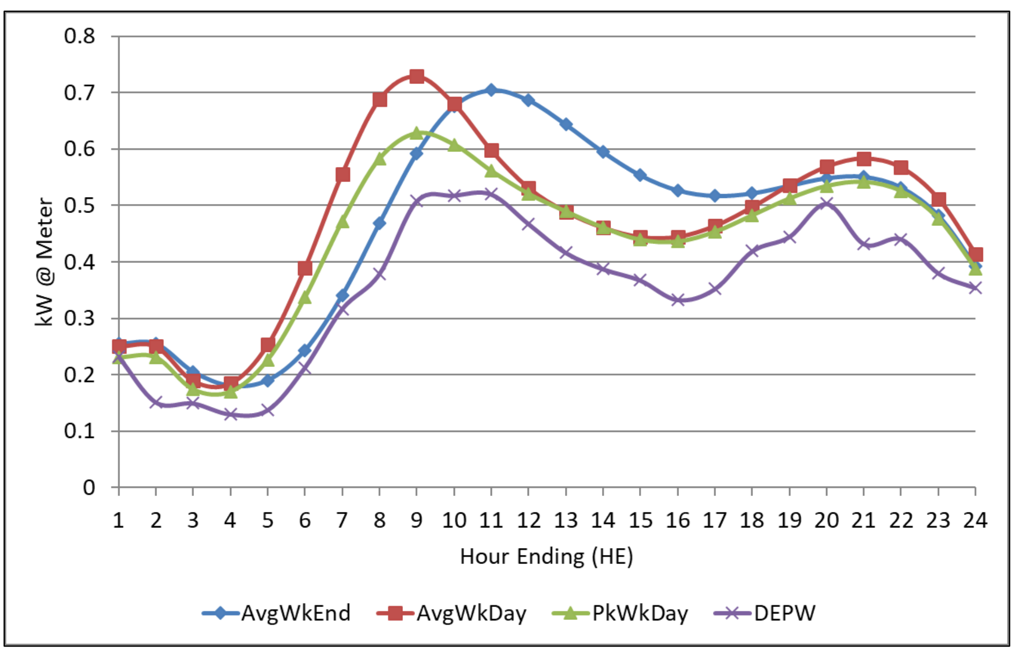
Resident Type	Fuel Type	Single-family detached	Single-family attached	Duplex	Condo	Apartment (3-4 units)	Apartment (5 or more units)	Mobile home
Owner	Electric	64%	50%	60%	76%			100%
	Natural Gas	36%	50%	40%	24%			0%
Renter	Electric	76%	82%	81%	84%	89%	91%	100%
	Natural Gas	24%	22%	19%	16%	11%	9%	0%

Figure 45. Water Heater Design Types



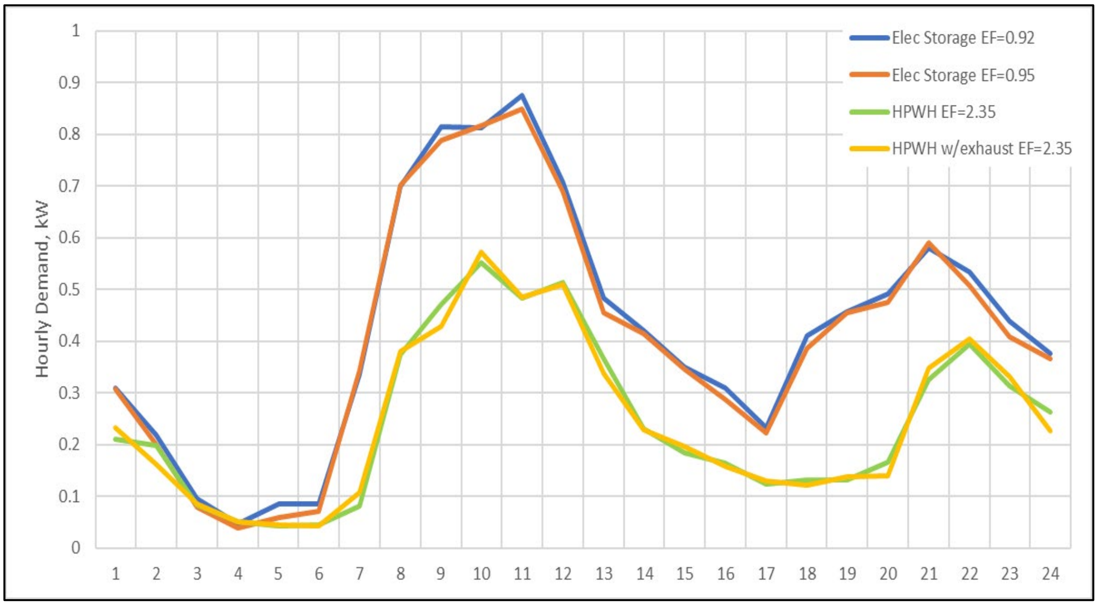
We reviewed various studies defining load shapes for electric water heaters, and these show load profiles similar to an EPRI study completed for the ECAR Region and DEP West, shown in Figure 43,[36] that feature a morning and evening peak. In general, these studies indicate weekday peak loads between 0.7 and 1.0 kW per unit occurring between 7:00 and 9:00 a.m. Using the BEopt model previously described we also compared the performance of resistance tank heaters to HP tank heaters. Figure 44 shows that heat pump heaters use approximately 29% less energy, which translates to 0.2 kW less demand per unit during morning operation.

Figure 46. Water Heater Load Shapes EPRI ECAR Region & DEP West



[36] KEY FILE - DEP West WH Load Shapes - MV 2014+2015 FROM BOB

Figure 47. Modelled Electric Water Heater Load Profiles



Similar to the heat pump space heating analysis, we wanted to get a sense of the technical demand related to residential electric hot water heating. As discussed previously, technical demand is defined as the MW that would result if all electric hot water heaters were operating at the same time and Table 30 indicates technical system demand of 2,147 MW based on the following assumptions:

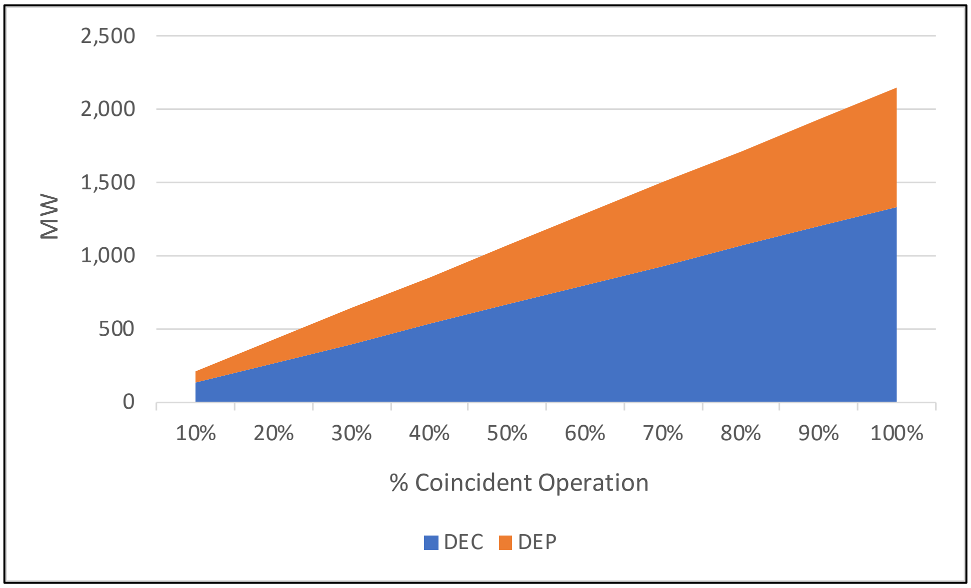
- As presented in 2019 RASS, 71% of all hot water heating systems are electric.
- Hot water heating represents about 10% of electric home demand during peak load periods where appliances and heat pumps are also operating coincident with the water heater.

Figure 45 shows the estimated hot water loads at various levels of coincident operation. For example, 60% coincident operating across the base of installed water heaters would result in a system demand of 1,288 MW. At this level of coincidence, hot water heating would account for about 10% of the 12,600 MW of total residential load on our study peak day as discussed at Table 25.

Table 30. Residential Dwelling and Electric Hot Water Heater Technical Demand

Dwelling Type	System	DEC	DEP
2 units	44	28	17
3 or 4 units	60	37	22
1-unit, attached	84	52	32
10 to 19 units	88	54	34
5 to 9 units	92	57	35
20 or more units	96	60	36
Mobile home	293	184	108
1-unit, detached	1,390	864	526
Total	2,147	1,337	811

Figure 48. Res Hot Water Heating Demand Operating Coincidence[37]



Solution Set Recommendations

Based on the proceeding analysis, this section defines our modelling inputs and expected 10-year savings trends for the following solution set components:

- Bring Your Own Thermostat (BYOT)
- Rate Enabled Thermostats (RET)
- Rate Enabled Residential Hot Water Heating Controls (RE-HWH)
- Winter Heat Pump Tune-up

The following discussion provides a summary of these solutions and related modelling input that are explained more fully in the separate report on Task 4 of our scope, Prepare Winter Peak Targeted DSM Plan.

Bring Your Own Thermostat (BYOT)

BYOT inputs assume a 2-hour preheat period between hours ending 5:00 and 6:00 am, followed by a three-degree setback occurring between hours ending 7:00 through 9:00. These events are activated by a third-party DSM aggregator and, during this time, we expect peak savings to be achieved in the hour ending at 7:00. During the 3-hour event, some systems will turn back on if the dwelling cannot maintain an acceptable temperature and as such, savings degrade over hours ending 8:00 and 9:00, as shown in Table 31. After the event, a 1-hour recovery period is expected during which the heating system activates to return the indoor temperature to settings determined by the occupant. Table 31 aggregates the hourly impacts defined in Table 31 and shows the modelling inputs for single and multifamily dwellings.

Table 31. Hourly BYOT kW Impacts by Dwelling Type

Dwelling Type	Usage Bin	Unit kW Yield in Hour Ending					
		5	6	7	8	9	10
2 units	Medium	-1.59	-0.85	1.64	0.87	0.62	-1.20

[37] KEY FILE - NC and SC ACS Data housing 2020.06.09

3 or 4 units	Low	-0.52	-0.30	0.90	0.50	0.40	-0.39
1-unit, attached	Medium	-1.59	-0.85	1.64	0.87	0.62	-1.20
10 to 19 units	Low	-0.52	-0.30	0.90	0.50	0.40	-0.39
5 to 9 units	Low	-0.52	-0.30	0.90	0.50	0.40	-0.39
20 or more units	Low	-0.52	-0.30	0.90	0.50	0.40	-0.39
Mobile home	Low	-0.52	-0.30	0.90	0.50	0.40	-0.39
1-unit, detached	High	-1.37	-0.84	1.71	0.96	0.71	-1.03

Table 32. Hourly BYOT kW Impacts for Single and Multifamily Dwellings

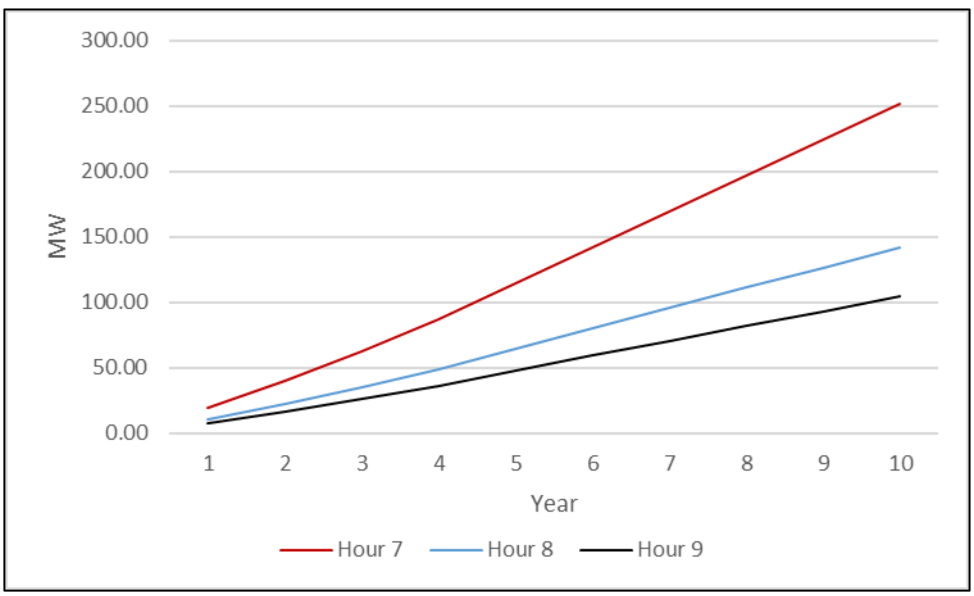
Hour Ending	5	6	7	8	9	10
SF	-1.38	-0.84	1.70	0.96	0.71	-1.04
MF	-0.60	-0.35	0.95	0.53	0.42	-0.45

Figure 46 shows the forecast by hour over a 10-year horizon based on the following assumptions:

- Annual growth during ramp: 10%
- Starting year 1 participation: 10,000
- Start Year: Dec-20

At the end of a 10-year implantation period we expect a peak load shed capacity of approximately 250 MW during the hour ending at 7, declining to 100 MW by the hour ending at 9.

Figure 49. 10-Year BYOT Savings Forecast by Hour



Rate Enabled Thermostats (RET)

Like BYOT, RET inputs assume a 2-hour preheat period between hours ending 5:00 and 6:00 am, followed by a two-degree setback occurring between hours ending 7:00 through 9:00. These events are triggered by thermostat settings provided by the thermostat manufacture and defined to coincide with peak utility rate schedules. During this time, we expect peak savings to be achieved in the hour ending at 7:00 and over a 3-hour event, some system will turn back on if the dwelling cannot maintain an acceptable temperature and as such, saving degrade over hours ending 8:00 and 9:00, as shown in Table 33. After the event, a 1-hour recovery period is expected during which the heating system activates to return the indoor temperature to settings determined by the occupant. Table 34 aggregates the hourly impacts defined in Table 31 and shows the modelling inputs for single and multifamily dwellings.

Table 33. Hourly RET kW Impacts by Dwelling Type

		Unit kW Yield in Hour Ending					
Dwelling Type	Usage Bin	5	6	7	8	9	10
2 units	Medium	-2.56	-1.35	2.23	1.30	0.93	-1.92
3 or 4 units	Low	-0.89	-0.53	1.16	0.71	0.56	-0.67
1-unit, attached	Medium	-2.56	-1.35	2.23	1.30	0.93	-1.92
10 to 19 units	Low	-0.89	-0.53	1.16	0.71	0.56	-0.67
5 to 9 units	Low	-0.89	-0.53	1.16	0.71	0.56	-0.67
20 or more units	Low	-0.89	-0.53	1.16	0.71	0.56	-0.67
Mobile home	Low	-0.89	-0.53	1.16	0.71	0.56	-0.67
1-unit, detached	High	-2.23	-1.29	2.03	1.41	0.98	-1.67

Table 34. Hourly RET kW Impacts for Single and Multifamily Dwellings

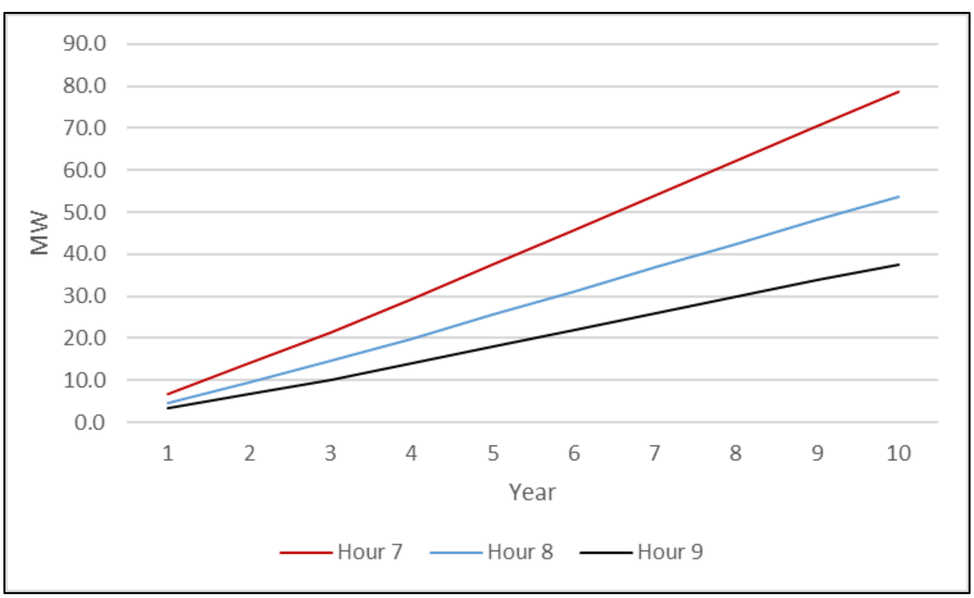
Hour Ending	5	6	7	8	9	10
SF	-2.23	-1.29	2.03	1.41	0.98	-1.67
MF	-1.02	-0.59	1.25	0.75	0.59	-0.76

Figure 47 shows the forecast by hour over a 10-year horizon based on the following assumptions:

- Annual growth during ramp: 5%
- Starting year 1 participation: 3,000
- Start Year: Dec-21

At the end of a 10-year implementation period we expect a peak load shed capacity of approximately 80MW during the hour ending at 7:00, declining to 40MW by the hour ending at 9.

Figure 50. 10-Year RET Savings Forecast by Hour



Rate Enabled Residential Hot Water Heating Controls (RE-HWH)

RE-HWH load shed events are triggered by controls provided by the water heater manufacturer designed to shed load coincide with peak utility rate schedules. Typically, these systems operate as follows:

- Electric hot water heaters can have high demand (e.g., 4 kW) when filled with cold water, but tanks typically operate in maintenance heat mode (i.e., prior to 6:00 a.m.) and draw about 0.3 kW. Demand increases to about 0.9 kW during morning periods when hot water is gradually being drawn from the tank and replenished by cold water supply.
- During shift events, no heat is provided to the tank and internal water temperature drops as cold water replenishes the tank during periods when the heating element is not operating.
- Once the shift event ends and the tank begins to heat, demand will typically spike to about 0.87 for tank heaters, as shown in Figure 48 and 0.55 kW for heat pump water heaters as shown in Figure 49.

Figure 51. Modelled Electric Storage Water Heater Peak Load Shed Profile

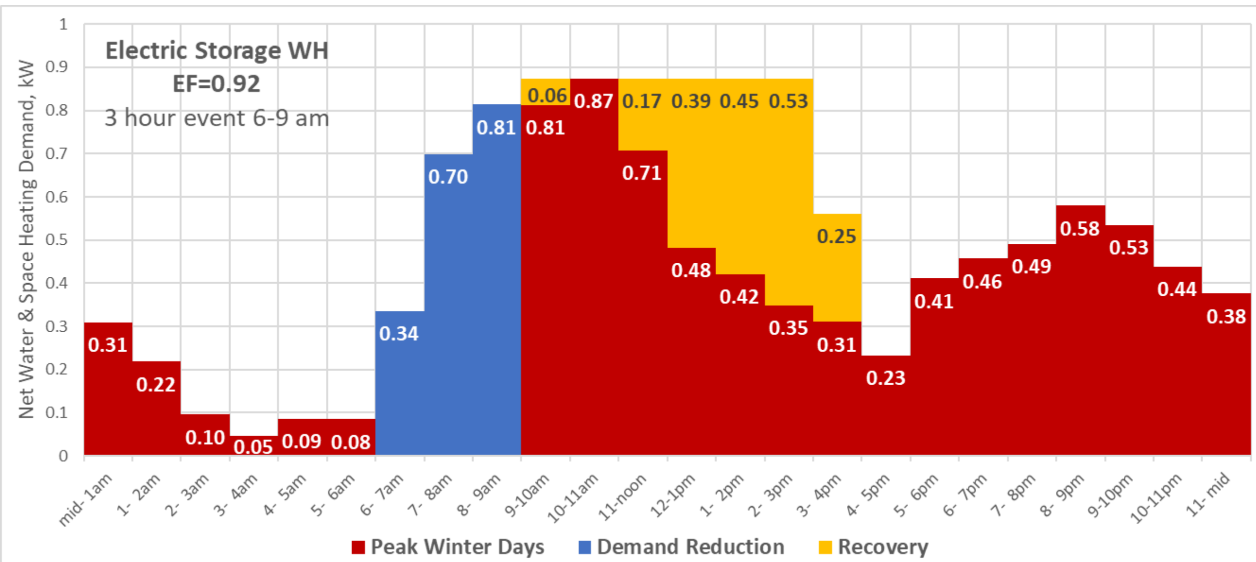
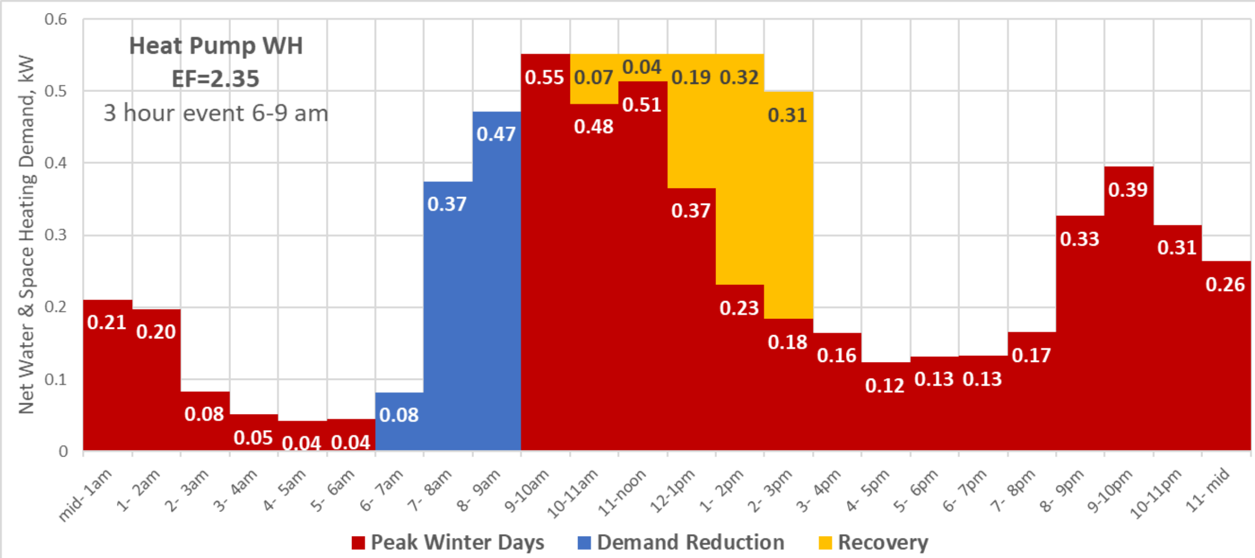


Figure 52. Modelled Heat Pump Water Heater Peak Load Shed Profile



RE-HWH inputs assume no preheat period and a 3-hour shut down beginning at the hour ending at 7:00. Savings are minimal during the first hour but increase as hot water is drawn down over time and normal heat recovery, which increases as hot water is drawn down, is deferred. After the event ends at the hour ending at 9:00, the tank resumes normal recovery heating mode which is extended through the hour ending at 15:00 as the tank recovers temperature on a larger volume of cold water than it would during normal operation because of the 3-hour event shut down. Table 35 shows the modelling inputs for single and multifamily dwellings.

Table 35. Hourly RE-HWH kW Impacts for Single and Multifamily Dwellings

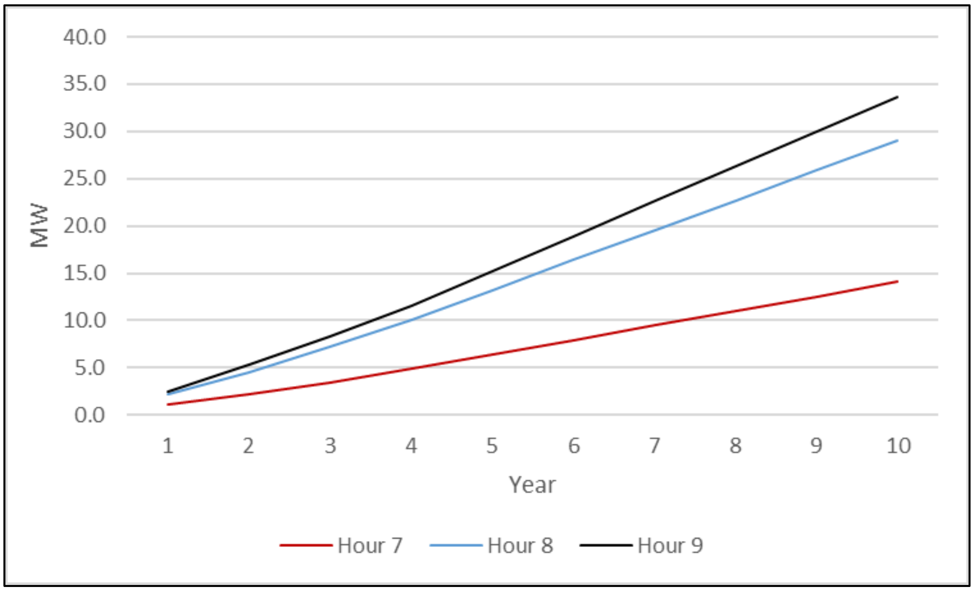
Hours Ending	5	6	7	8	9	10	11	12	13	14	15	16
SF	0.00	0.00	0.34	0.70	0.81	-0.06	0.00	-0.17	-0.39	-0.45	-0.53	-0.25
MF	0.00	0.00	0.26	0.53	0.61	-0.05	0.00	-0.13	-0.29	-0.34	-0.40	-0.19

Figure 50 shows the forecast by hour over a 10-year horizon based on the following assumptions:

- Annual growth during ramp: 10%
- Starting year 1 participation: 3,100
- Start Year: Dec-21

At the end of a 10-year implementation period we expect a peak load shed capacity of approximately 15MW in the hour ending at 7:00, increasing to 35MW during hour ending 9:00.

Figure 53. 10-Year RE-HWH Savings Forecast by Hour



5. Small and Medium C&I Market and Solutions

Rate Definitions

We segmented the commercial and industrial sector into two cohorts, small and medium C&I and large C&I, which is discussed later in this report. Small and medium C&I customers include the following rate types:

- General service rates that are not time differentiated (i.e., flat rates) though may have seasonal components.
- TOU rates targeting the same flat rate customers, but with demand threshold that are lower than TOU and RTP rates offered to larger C&I customers. These customers, in aggregate, account for only a small percentage of system load.

Table 36 provides summary rates for the small and medium C&I sector which align with the demand and consumption data reviewed for 2018, including the distribution between TOU and flat rates. Virtually all DEC small and medium C&I customers are on flat rates except for several TOU pilots with limited participation for small commercial customers. In general, DEC accounts for 40% of small and medium C&I customers and about 11% of total system demand, while DEP account for about 60% of small and medium C&I customers and about 17% of total system demand. About 63% of DEP customer are on flat rates, with the remainder of TOU rates applicable to small, medium, and large customers. Overall, TOU rates account for 22% of demand for the small and medium C&I rates defined in Table 36, the majority of which is associated with the DEP MGS-TOU.

Table 36. Small and Medium C&I Rates Summary

System	Schedule	Tier Type	Winter On-Peak	Winter	Study Peak Day MW	% C&I Cohort Demand	KW Cap
DEC	SGS	Tiered kWh and KW	None	None	1,154	17%	<50
	SGS-CPP (Pilot)	As Posted	6:00 a - 10:00 a	Oct – April			<50
	SGS-TOU-CPP (Pilot)	As Posted	6:00 a - 10:00 a	Oct – April			<50
	SGS-TOUD-DPP (Pilot)	As Posted	6:00 a - 10:00 a	Oct – April			<50
	LGS	Tiered kWh and KW	None	None	1,091	16%	>75
	I	Tiered kWh and KW	None	None	470	7%	None
DEP	SGS	Tiered kWh	None	None	557	8%	<30
	SGS-TOUD-58	On/Off kWh	6:00 a - 1:00 p	Sept - Mar	64	<1%	>30
	SGS-TOUE-58	On/Should/Off kWh	6:00 a - 1:00 p	Sept - Mar			>30
	MGS-58	None	None	None	1,853	27%	30<1,000
	MGS-TOU	Not reviewed	Not reviewed	Not reviewed	1,212	18%	30<1,000
	LGS-58	Tiered KW	None	Oct – June	189	3%	>1,000
	LGS-TOU-58	Tiered kWh and KW	6:00 a - 1:00 p	Oct – May	290	4%	>1,000

Peak Load Profile

The following section provides observations for DEC and DEP load profiles based on a review of 8,760 hourly load data for the small and medium C&I rates defined in Table 37.

DEC

Figure 51 shows average summer and winter peak day as defined at Table 3 for SGS, indicating higher demand during summer is likely due to air conditioning, if demand from other commercial equipment (e.g., lighting, office equipment, process equipment, etc.) are not weather sensitive and constant throughout the year. To assess sensitivity to weather events in the winter, Figure 52 compares demand between the study peak day and the average winter peak days, showing a difference of 71 MW, which we attribute to increased electric heating loads.

Figure 54. DEC 2018 SGS Demand Profile – Average Season Peak Day

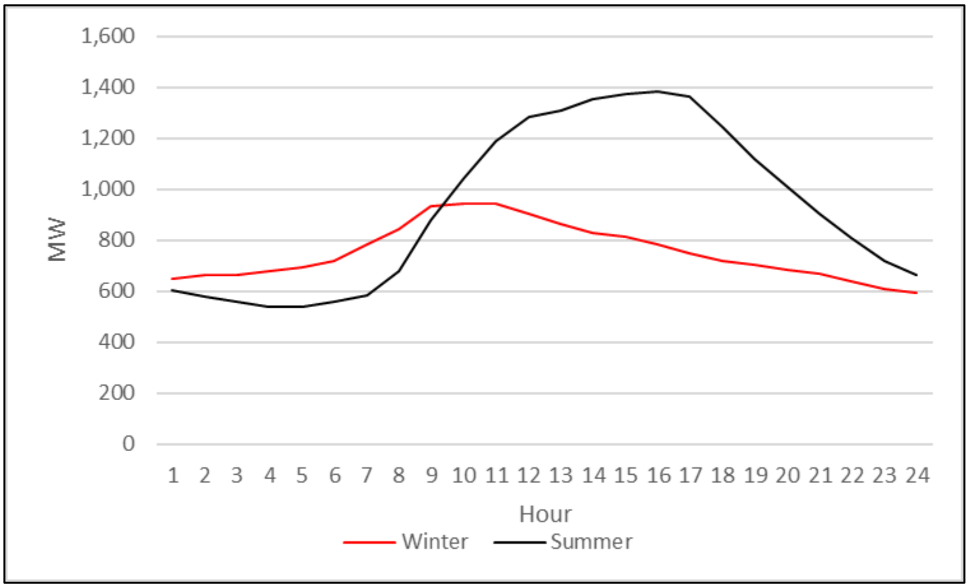
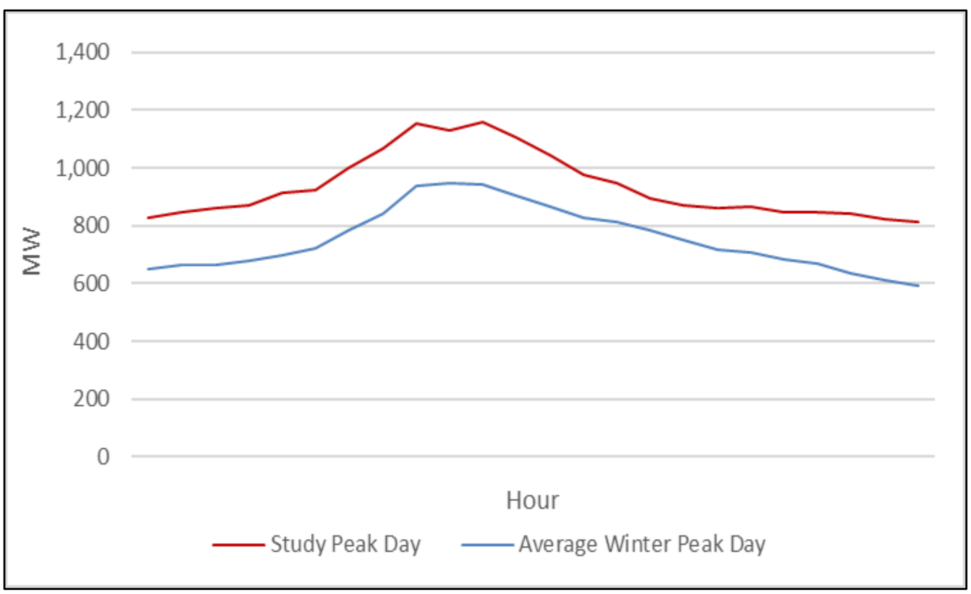


Figure 55. DEC 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



We completed a similar analysis for the DEC LGS rate and Figure 53 shows average summer and winter peak day for LGS, like the SGS rate. Figure 54 compares demand between the study peak day and the average winter peak days, showing a difference of 11 MW, indicating this rate class is minimally sensitive to weather events.

Figure 56. DEC 2018 LGS Demand Profile - Average Season Peak Day

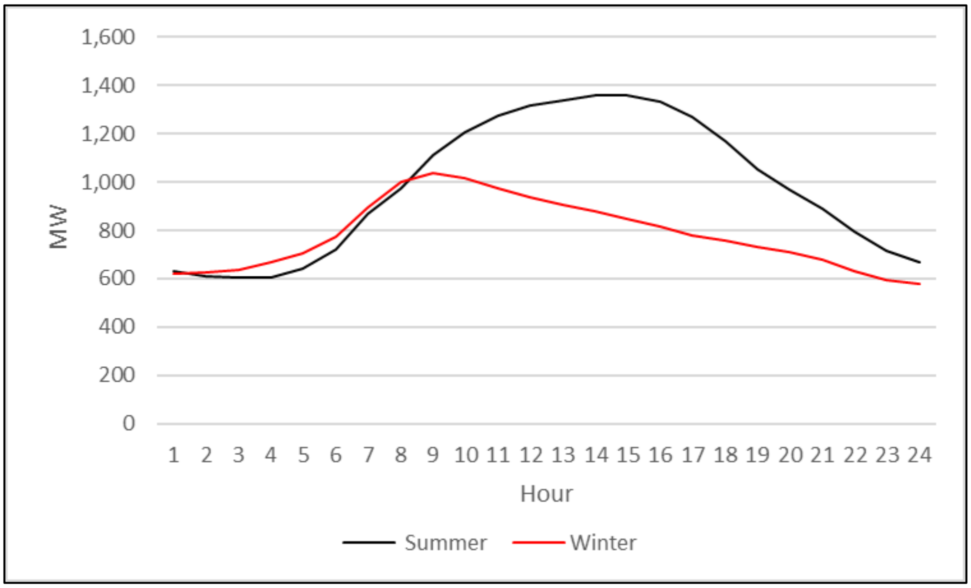


Figure 57. DEC 2018 LGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day

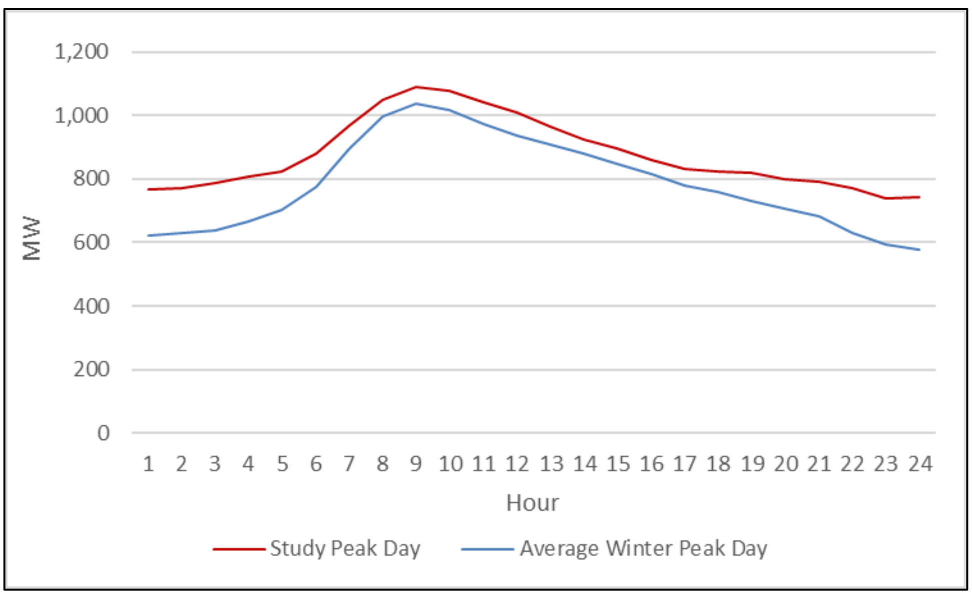


Figure 55 and Figure 56 show a similar review of the DEC Ind rate, indicating that these customers are a blend of industrial and commercial operations though no segment data was provided. These load shapes are virtually identical, and while there is some demand associated with electric heating, most of the demand is likely from non-weather sensitive loads. The difference in demand between the study peak day and the average winter peak days, showing a difference of 30 MW, or an increase of about 5%, indicating that this rate class is not very sensitive to weather events.

Figure 58. DEC Ind Demand Profile - Average Season Peak Day

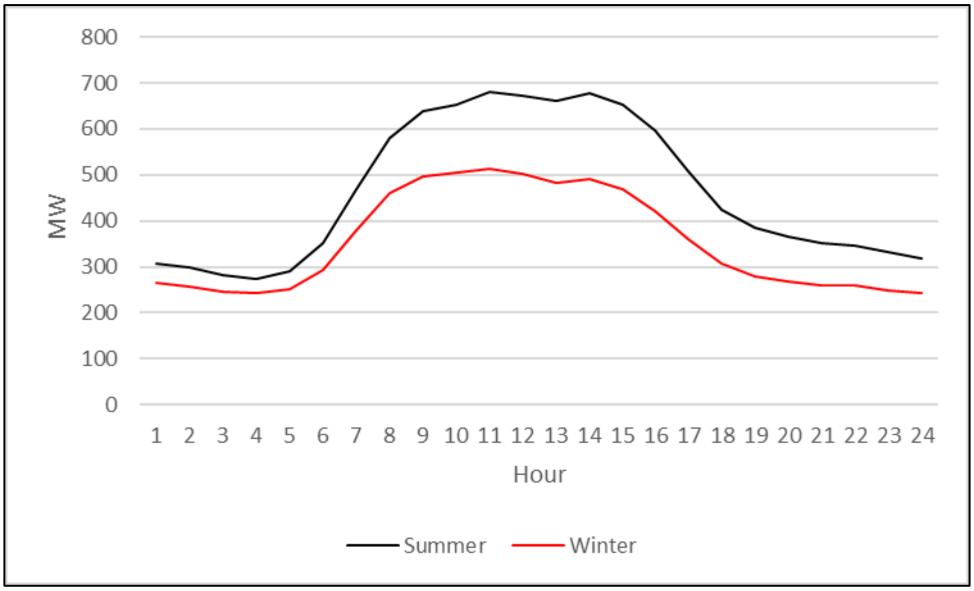
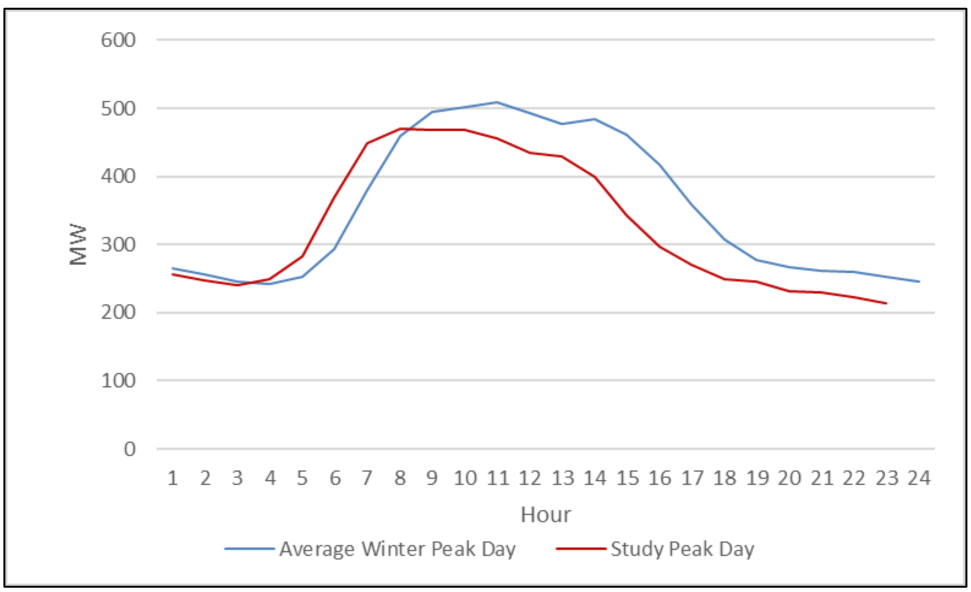


Figure 59. DEC 2018 Ind Demand Profile – Study Peak Day Vs. Average Winter Peak Day



The data reviewed for the SGS, LGS, and Industrial rates allowed us to complete a rough estimate of morning heat loads by averaging demand during a heating period that we defined from 8:00 am to noon, minus the average afternoon demand occurring during other business day hours from 1:00 p.m. to 5:00 p.m. Table 37 shows the average hourly winter morning heating demand (MW) by C&I rate for the study peak day as well as the average of 6 winter peak days, indicating a difference 112 MW between the average winter peak and annual system peak.

Table 37. DEC Average Winter Peak Morning Heating Demand (MW) by Rate

Rate	SGS	LGS	Ind	Total
Study Peak Day MW	177	158	82	417
Ave Peak Day MW	106	147	52	305

DEP

As noted at Table 37, about 63% of DEP C&I customer are on rates that have no time differential and 37% are on TOU rates, including the combinations:

- SGS and SGS-TOU
- MGS and MGS-TOU
- LGS and LGS-TOU

We compared the aggregate C&I load shapes for flat rate and TOU customers as shown in Figure 57 for 6 winter system peak days and Figure 58 for 4 summer system peak days in 2018. Because of the high saturation of TOU across DEP general service customers (37%) this analysis implies a response that shifts demand off-peak during winter peak (6:00 a.m. - 1:00 p.m.) and summer peak (10:00 a.m. -10:00 p.m.). We did not research if these are behavioral driven (i.e., actively managing demand during peak) or simply customers selecting a TOU rate that is best suited to their standard operating profile. We caveat this analysis because the data provided to us included TOU customers within the flat rate totals (e.g., the SGS load profile includes the SGS-TOU, etc.). Had flat rate and TOU been broken out as discrete profiles we expect the difference between flat rate and TOU customers would be more pronounced.

Figure 60. DEP Small-Medium C&I Aggregate Rate Demand Profile - Average Winter Peak Day

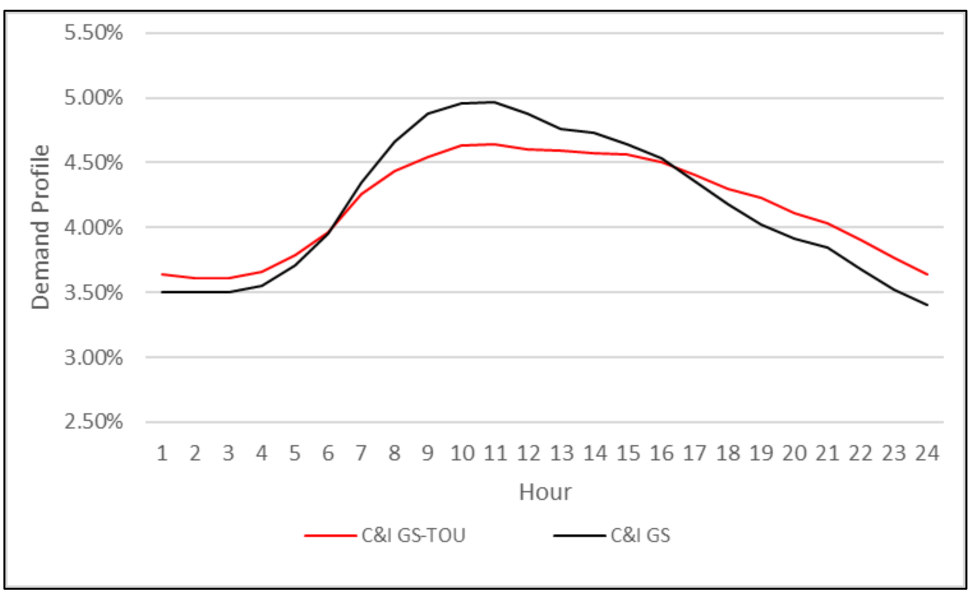
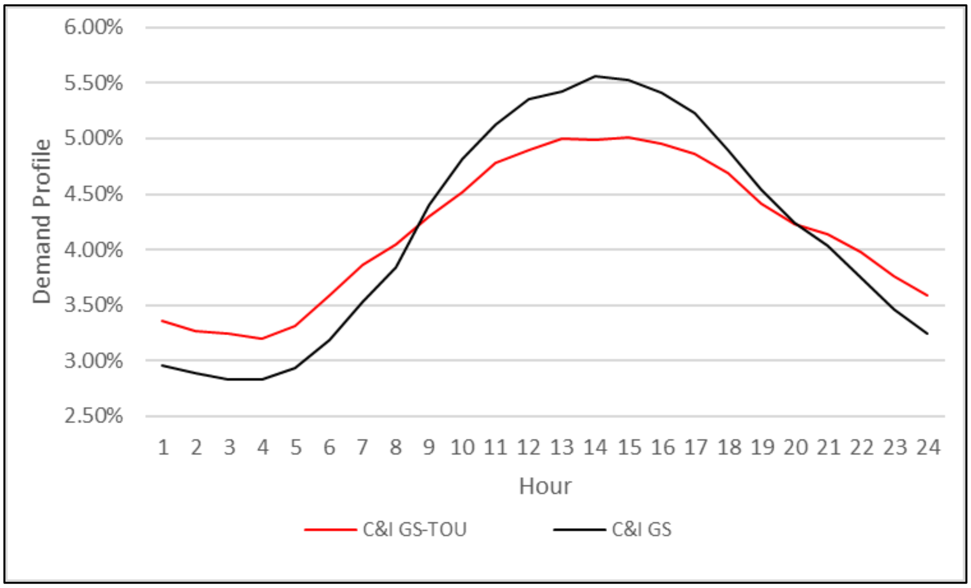


Figure 61. DEP Small-Medium C&I Aggregate Rate Demand Profile - Average Summer Peak Day



Like the DEC SGS analysis, Figure 59 shows average summer and winter peak day for DEP SGS, indicating higher demand during summer is likely due to air conditioning. Figure 60 compares demand between the study peak day and the average winter peak days, showing a difference of 127 MW, or an increase of about 25% between the study peak and average winter peak day, indicating that this rate class is sensitive to weather events.

Figure 62. DEP 2018 SGS Demand Profile - Average Season Peak Day

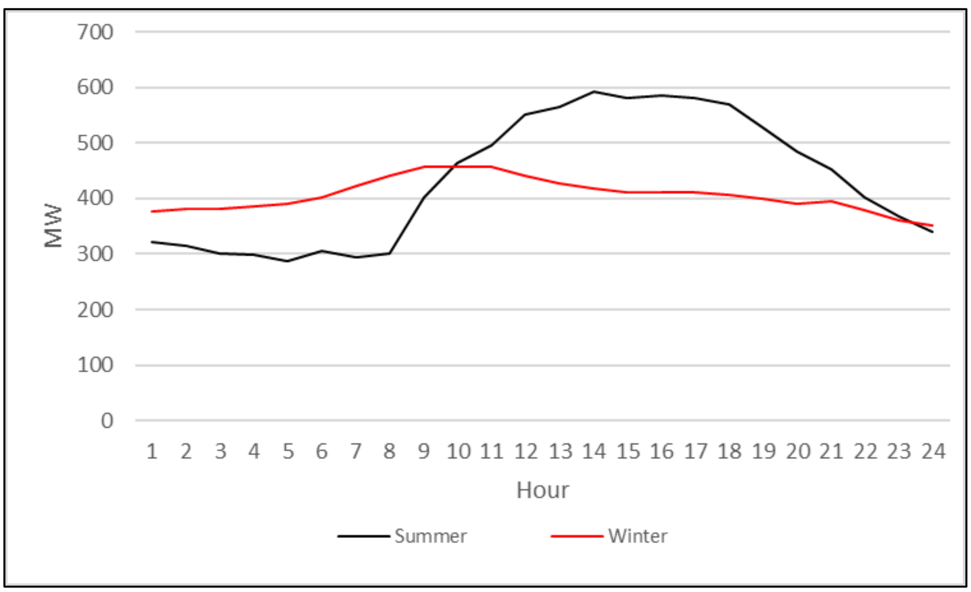
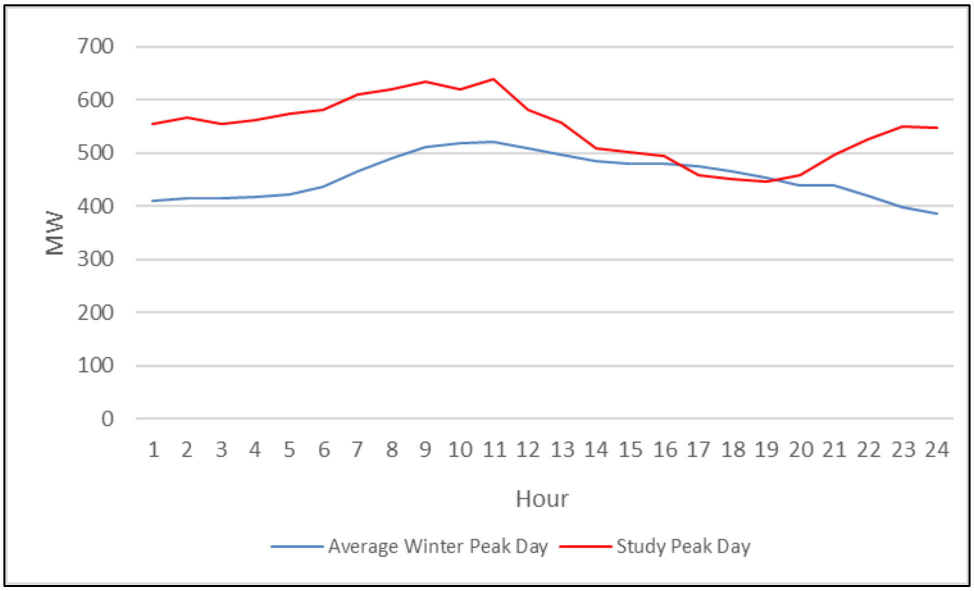


Figure 63. DEP 2018 SGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



Similarly, Figure 61 shows average summer and winter peak day for MGS, indicating a higher demand during summer similar to the SGS rate. Figure 62 compares demand between the study peak day and the average winter peak days, showing a difference of 4 MW, indicating that this rate class has demand associated with heating, but it is not sensitive to weather events.

Figure 64. DEP 2018 MGS Demand Profile – Average Season Peak Day

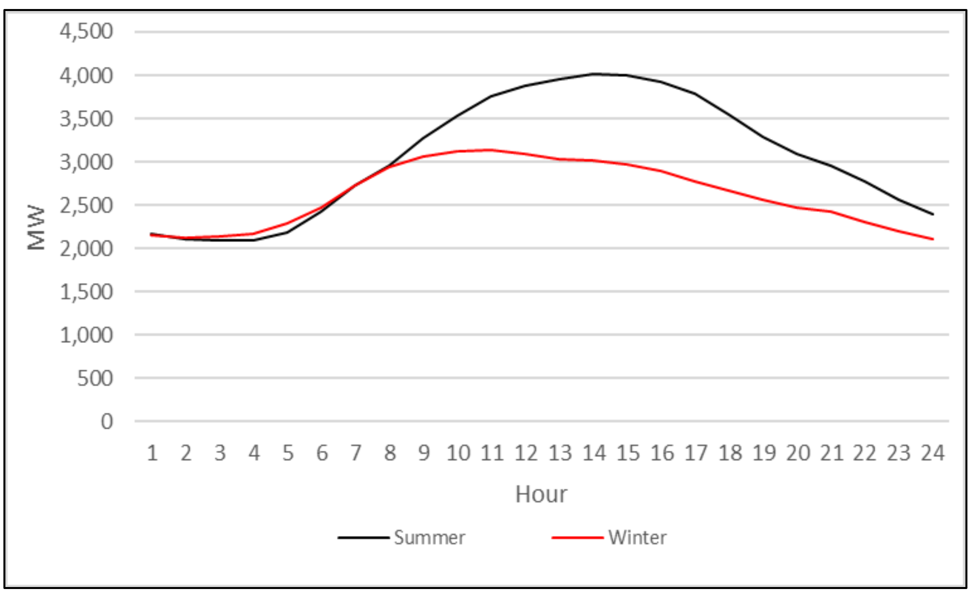


Figure 65. DEP 2018 MGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day

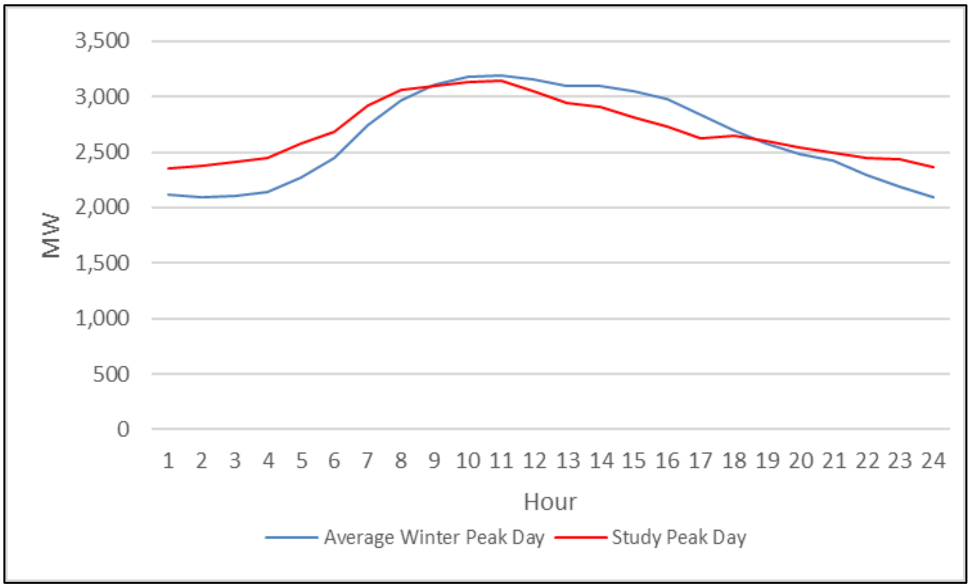


Figure 63 shows average summer and winter peak day for the LGS rate, indicating a higher demand during summer, similar to the SGS rate. Figure 64 compares demand between the study peak day and the average winter peak days, showing a difference of -8 MW, indicating that this rate class is not sensitive to weather events.

Figure 66. DEP 2018 LGS Demand Profile – Average Season Peak Day

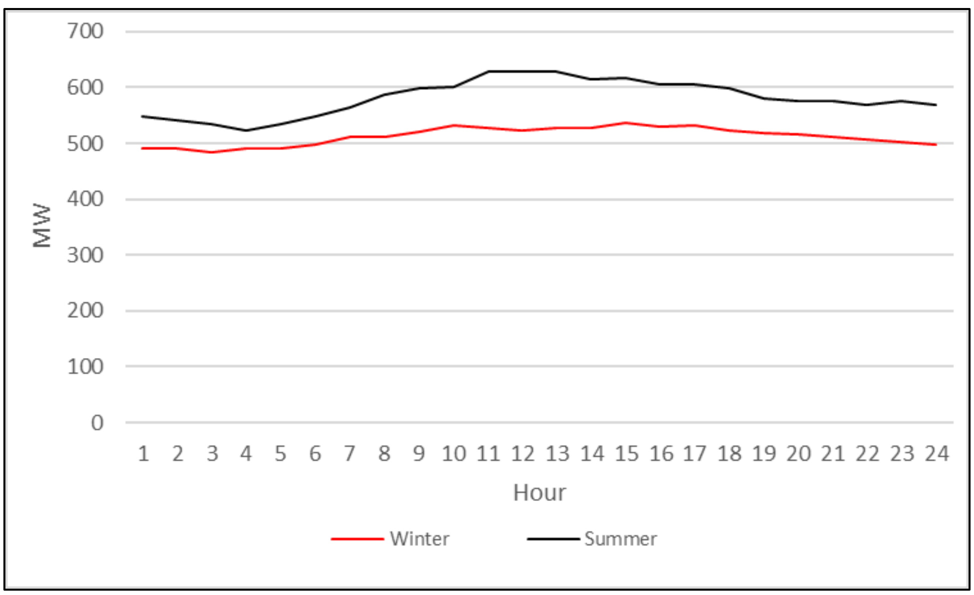
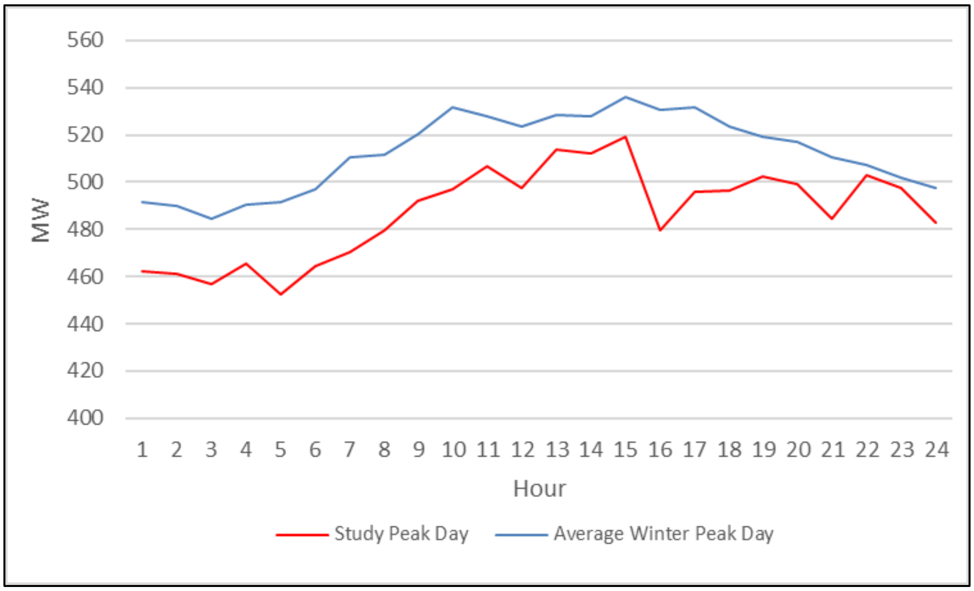


Figure 67. DEP 2018 LGS Demand Profile – Study Peak Day Vs. Average Winter Peak Day



Using the methodology described for DEC, Table 38 shows the average hourly winter morning heating demand (MW) by C&I rate for the study peak day and average of 6 winter peak days, indicating a difference of 34 MW between the average winter peak and annual system peak. We estimate that there is no appreciable winter space heating demand for LGS customers.

Table 38. DEP Average Hourly Winter Peak Heating Demand (MW) by Rate

Rate	SGS	MGS	LGS	Total
Study Peak Day MW	127	292	-6	413
Ave of Peak Day MW	92	288	-14	366

Table 38 summarizes our estimates of winter peak electric heating demand by rate for DEC and DEP.

Table 39. Average Hourly Winter Peak Electric Heating Demand (MW) by Rate

Utility	Rate	SGS	MGS	LGS	Ind	Total
DEC	Study Peak Day MW	177	-	158	82	417
	Ave Peak Day MW	18	-	82	51	151
DEP	Study Peak Day MW	127	292	-6		413
	Ave of Peak Day MW	92	288	-14		366
Total	Study Peak Day MW	304	292	152	82	830
	Ave Peak Day MW	52	109	78	51	517

To gain further perspective on DEP C&I winter heating loads, we reviewed 2018 data for 327 DEP large accounts, most of which will be flat rate customers but some of which are RTP customers. We binned this data to define customers with average winter morning peak demand that equals or exceeds average winter demand for the balance of the business day. For this analysis, the morning period we defined the morning heating period as hours ending 7:00 through 9:00, and the balance of the business day was defined as hours ending 10:00 through 5:00.

Table 40 shows that 39% of 327 large accounts have average morning demand exceeding afternoon, accounting for 57% of average morning load, or 639 MW out of 1,129 MW of the average demand for 327 DEP large accounts for hours 7:00 through 9:00. To refine this estimate, we looked at customers the morning peak exceeding the balance of the business day demand by 110% and 120% At the extreme about 23 customers (7%) have morning peak exceeding the balance of the business day by 120%, or 84 MW out of 1,129 MW average morning demand for the accounts reviewed.

Table 40. DEP Large Commercial Customer Morning Demand Comparison – Average Season Peak Day

Bin	Customers	% of Customers	Average Morning Demand (MW)	% of Total Average Morning Demand
100%	129	39%	639	57%
110%	46	14%	222	20%
120%	23	7%	84	7%

Figure 65, Figure 66, and Figure 67 show the demand profiles for our analysis bins, showing a clear morning peak for accounts where morning peak exceeded afternoon peak by 120%. Collectively, this analysis indicates:

- About 40% of these customers likely use natural gas for most of their heating.
- Between 50% and 60% % of customers have some electric heat, likely for space heating, and this accounts for about 148 MW of winter morning peak for hours ending 7:00 through 9:00.

Figure 68. DEP Large C&I Morning Peak Exceeds Afternoon Peak – Average Season Peak Day

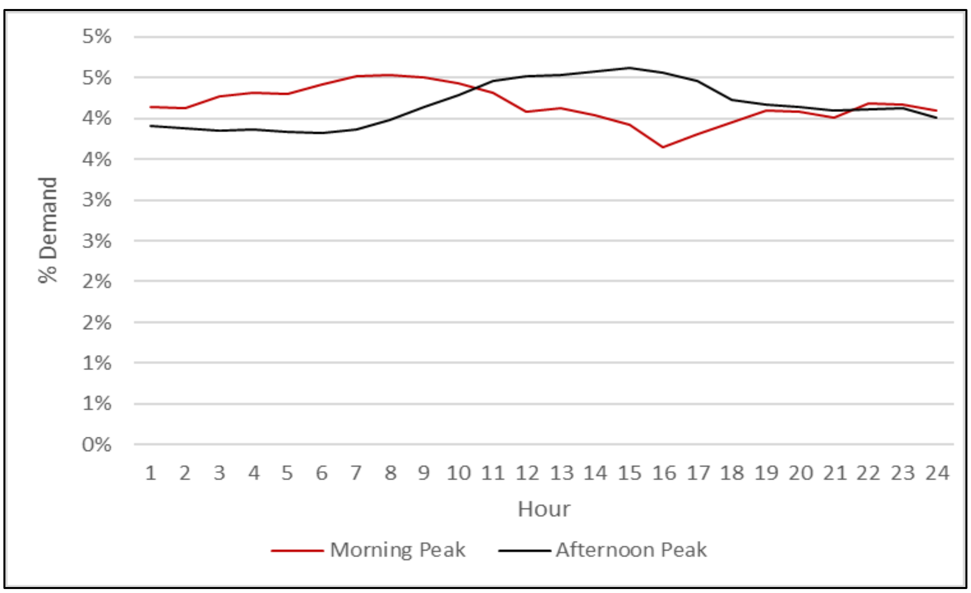


Figure 69. DEP Large C&I Morning Peak Exceeds Afternoon Peak by 10% – Average Season Peak Day

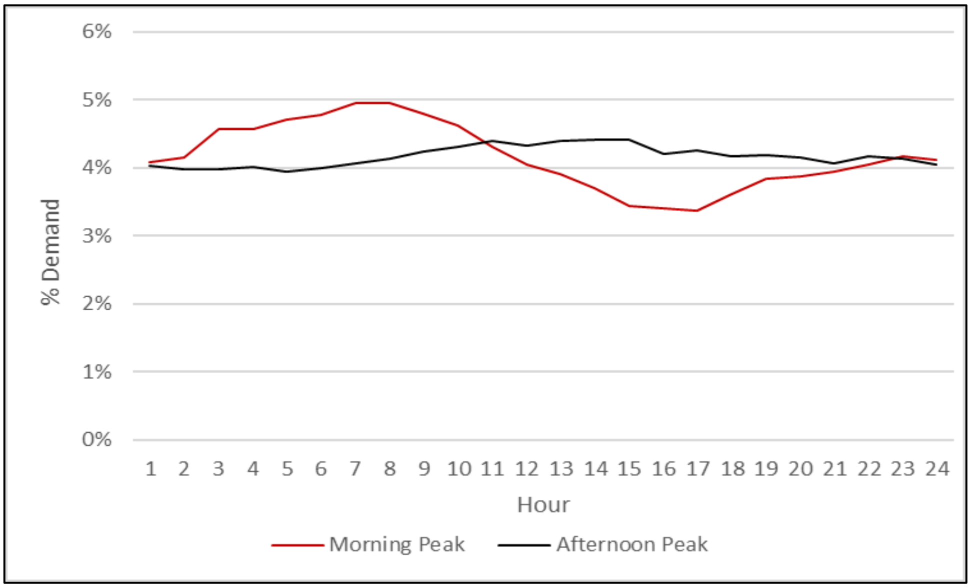
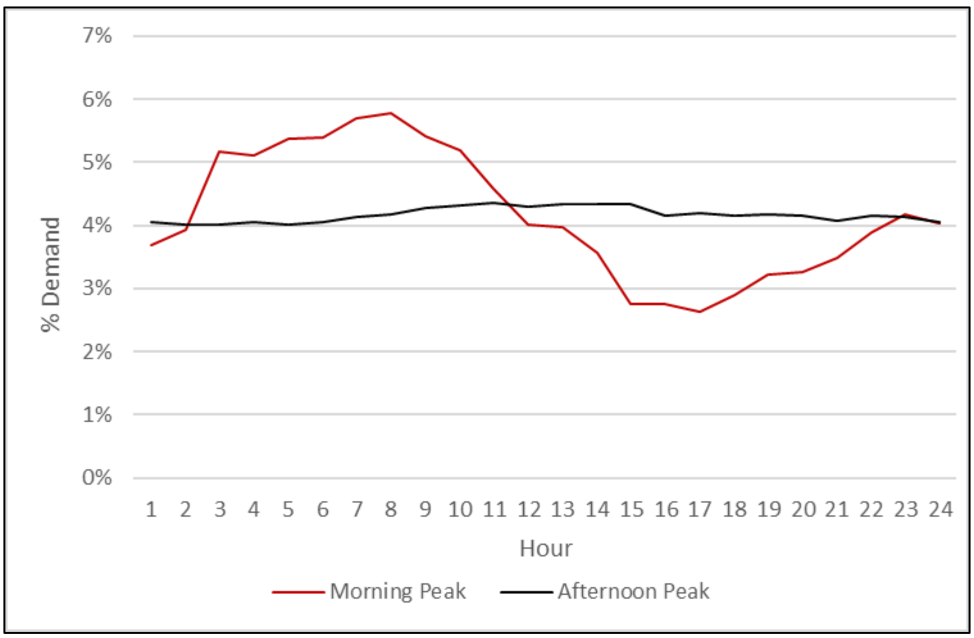


Figure 70. DEP Large C&I Morning Peak Exceeds Afternoon Peak by 20% – Average Season Peak Day



Market Characteristics

The following section discusses market characteristics of key drivers in C&I peak winter morning peak demand.

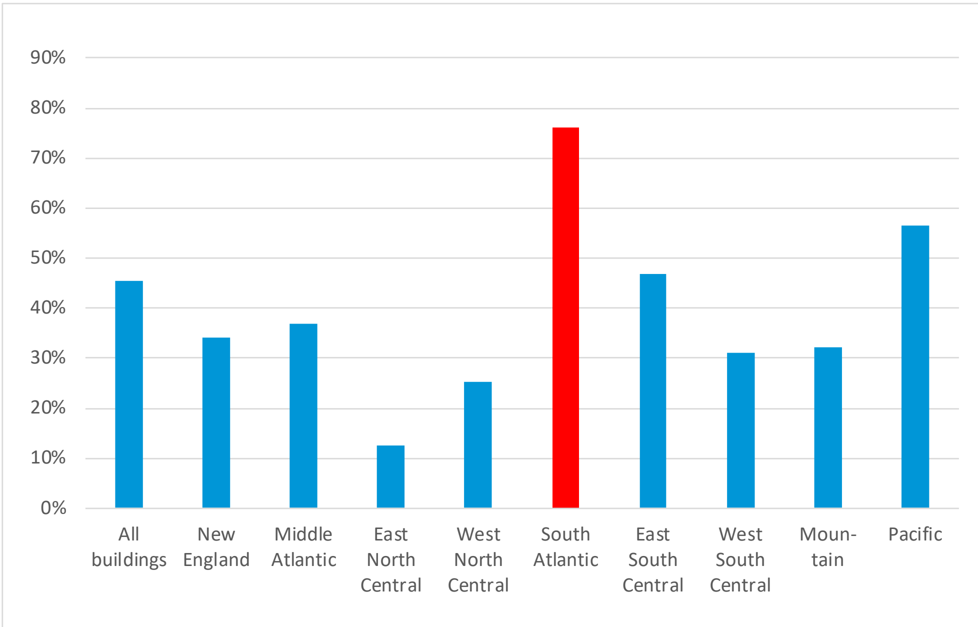
Space Heating

DEC and DEP are in the South Atlantic of the 2012 Commercial Buildings Energy Consumption Survey (CBECS). This survey, administered by the Energy Information Administrations (EIA)[38] indicates that heat

[38] Accessed April 2020 at https://www.eia.gov/consumption/commercial/

pumps are the primary space heating source in 77% of commercial buildings,[39] compared to approximately 60% of buildings nationally and as shown in Figure 68, this is the highest saturation of heat pumps in any CBECS region.

Figure 71. Heat Pump as Primary Commercial Heat Source by CBECS Region



To define how many buildings might be heated with heat pumps, we first used EIA to estimate the number of Duke commercial customers within the CBECS South Atlantic region, and Table 41 shows that 18% of the region's utility customers are Duke utilities in NC and SC.

Table 41. Distribution of Duke Commercial Customers in CBECS South Atlantic Region

	Region			% of CBEC Region		
Utility	System	SC	NC	SC	NC	System
DEC	375,072	94,117	280,955	3%	8%	11%
DEP	236,723	31,801	204,922	1%	6%	7%
Duke Total	611,795	125,918	485,877	4%	14%	18%

We applied these customer percentages to CBECS building counts to estimate the total number of DEC and DEP buildings heated with heat pumps, as well as tons of capacity, and technical demand[40] based on the following assumptions:

- We binned our saturation of heat pumps by building type based on average size and professional judgement, including:
  - 60% saturation for facilities under 12,000 sq. ft.
  - 40% for facilities under 20,000,
  - 20% for facilities larger than 200,000 sq. ft., with some adjustment for select segments, such as a lower saturation in large warehouses.

[39] This is saturation of building count, not saturation of square footage
[40] Defined as total demand if all systems are operating at the same time

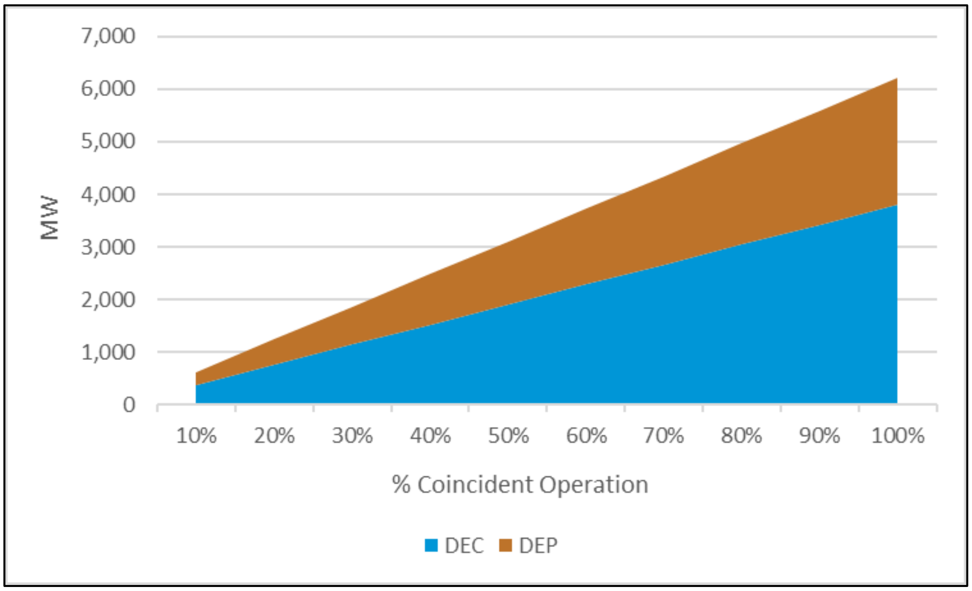
- 3.5 kW/ton
- 630 sq. ft./ton for all building type except for warehouse and storage, where we estimate 3,000 sq. ft. / ton

As shown in Table 42, based on the assumptions above our analysis indicates that approximately 78,000 buildings are heated with heat pumps in roughly 1,280 MM of conditioned space. This represents 2 million tons of capacity and a technical load of 6,207 MW. Based on our previous estimate that heat pumps account for 830 MW of load at hour 8:00 on our study peak day, as presented in the discussion preceding Figure 12, this implies an estimate coincident operation of about 13% across the C&I sector. We consider this reasonable because these systems are installed in a wide diversity of businesses with different operating schedules, structure types, commercial uses, and system duty cycles. Figure 69 shows our estimated system demand from commercial heap pumps at various levels of operating coincidence.

Table 42. Estimated Heat Pump Heating Technical Demand

Segment	Total Bldgs.	Heat Pump Bldgs.	Million Sq. Ft.	Tons	Technical MW
Education	15,414	6,166	201	318,671	1,117
Food sales	7,087	4,252	20	31,643	111
Food service	13,819	8,292	42	66,652	234
Health care Inpatient	253	51	14	22,722	80
Health care Outpatient	3,721	744	9	14,419	51
Lodging	5,847	3,508	129	204,836	718
Mercantile Retail (other than mall)	16,300	6,520	75	118,043	414
Mercantile Enclosed and strip malls	9,036	3,614	120	190,081	666
Office	35,080	7,016	113	178,579	626
Public assembly	7,973	3,189	64	101,436	355
Public order and safety	2,773	1,109	61	96,162	337
Religious worship	14,174	8,504	91	144,244	505
Service	17,717	10,630	79	124,719	437
Warehouse and storage	31,359	12,544	201	63,555	223
Other	3,012	1,807	60	95,601	335
Total	183,563	77,946	1,279	1,771,363	6,207

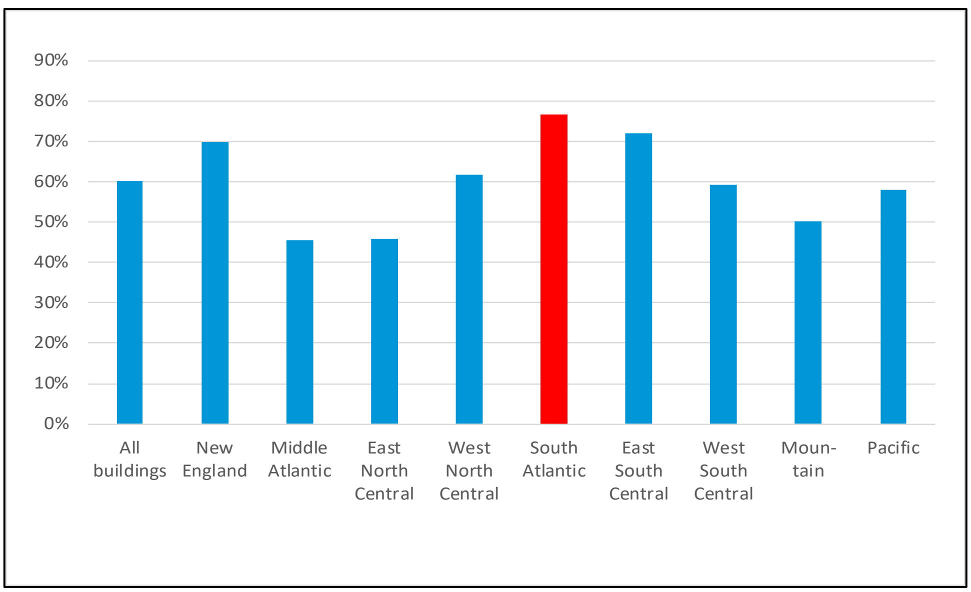
Figure 72. Commercial Heat Pump Operating Coincidence Demand



Hot Water Heating

Using the same CBES data discussed for heat pump space heating, Figure 70 shows that electric hot water heaters are their primary source of hot water for 78% of commercial buildings.

Figure 73. Electric Hot Water Heaters as Primary Commercial Source by CBECS Region



In addition to high saturation, the market appears to be shifting towards electric water heating in commercial applications. As discussed in an EIA technology forecast update, [41] Figure 71 shows that annual shipments of commercial electric water heaters have increased from 24,000 units in 1997 to about 128,000 units in 2017. This is in contrast with annual shipments of gas fired hot water heaters which has

[41] EIA -Technology Forecast Updates – Residential and Commercial Building Technologies –Advanced Case. Navigant April 2018

fluctuated between 80,000 units to 100,000 units annually during this same timeframe, as shown in Figure 72.

Figure 74. Commercial Electric Hot Water Heater Shipment Trends

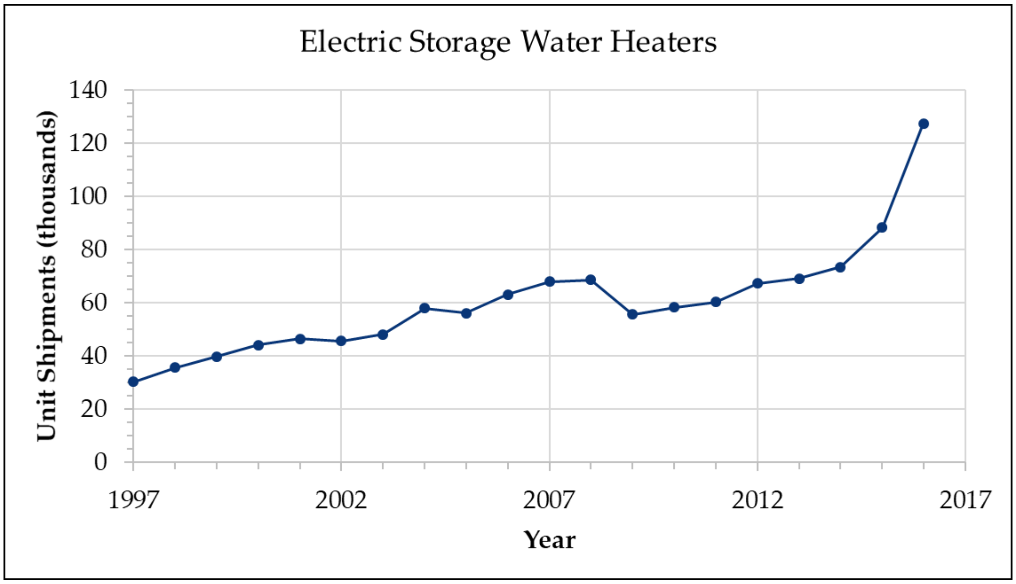
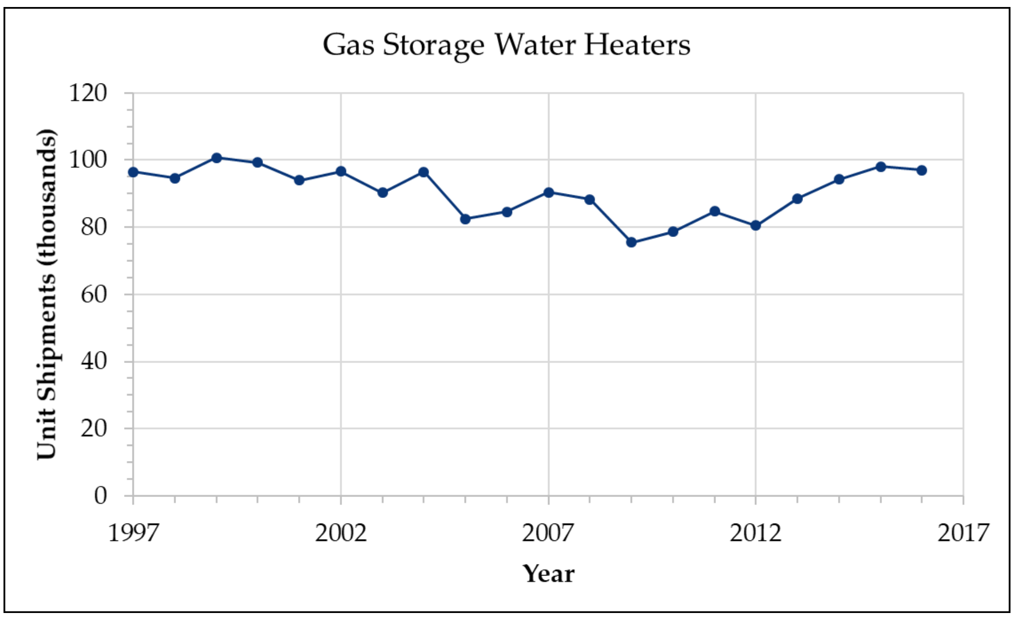


Figure 75. Commercial Natural Gas Hot Water Heater Shipment Trends



We estimated commercial electric hot water heating (CHWH) technical demand using the same approach as our analysis of commercial heat pump space heating. First, we estimated total building counts and assumed CHWH saturation by segment to define the number of buildings with CHWH consistent with CBECS regional estimates. We then used the following assumptions to estimate the number of CHWH units installed and the resulting technical demand[42]:

- Average commercial area per HWH = 10,000 sq. ft. for all building type except for warehouse and storage, where we estimate 1 HWH per building

[42] Defined as total demand if all systems are operating at the same time

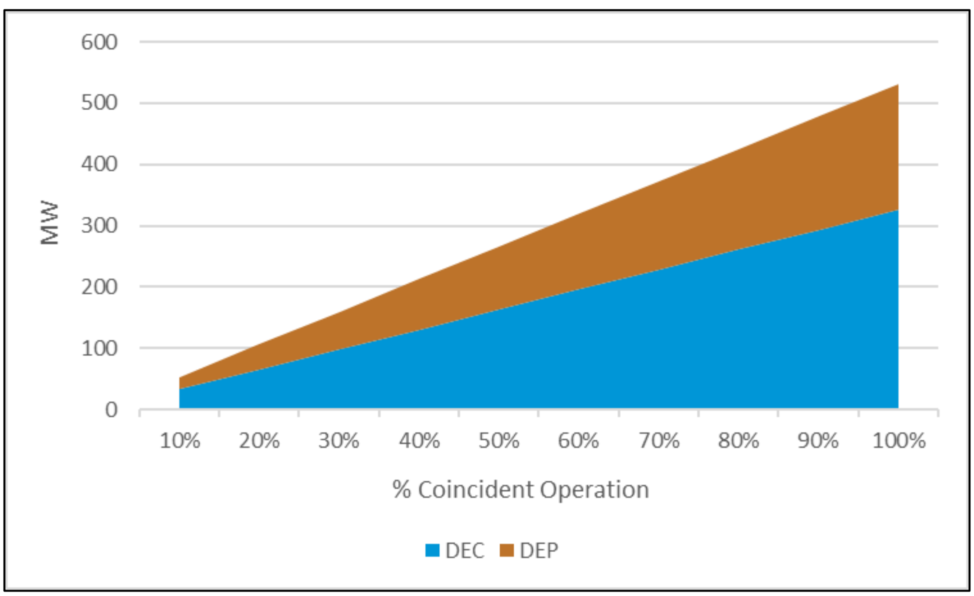
- Ratio of commercial CHWH heater size to average residential CHWH size = 2.38
- Average kW demand during winter morning peak period = 1.93 kW

As shown in Table 43, based on the assumption above our analysis indicates that approximately 132,000 buildings use CHWH tanks, totalling approximately 300,000 units, representing 532 MW of technical MW demand. Figure 73 shows our estimated system demand from commercial electric water heaters at various levels of operating coincidence.

Table 43. Estimated Electric HWH Technical Demand

Segment	Total Buildings	EHWH Saturation	EHWH Buildings	Ave Sq. Ft.	EHWH Units / Building	Total Units	Technical Demand (MW)
Education	15,414	60%	9,248	32,644	4	36,993	71
Food sales	7,087	40%	2,835	4,700	1	2,835	5
Food service	13,819	40%	5,528	5,077	1	5,528	11
Health care Inpatient	253	20%	51	283,500	29	1,468	3
Health care Outpatient	3,721	60%	2,232	12,238	2	4,465	9
Lodging	5,847	40%	2,339	36,879	4	9,355	18
Mercantile Retail (other than mall)	16,300	80%	13,040	11,435	2	26,080	50
Mercantile Enclosed and strip malls	9,036	80%	7,229	33,216	4	28,914	56
Office	35,080	80%	28,064	16,076	2	56,128	108
Public assembly	7,973	80%	6,378	20,089	3	19,134	37
Public order and safety	2,773	80%	2,218	54,753	6	13,311	26
Religious worship	14,174	80%	11,339	10,713	2	22,678	44
Service	17,717	80%	14,174	7,410	1	14,174	27
Warehouse and storage	31,359	80%	25,087	16,000	1	25,087	48
Other	3,012	80%	2,410	33,412	4	9,638	19
Total	183,563	72%	132,171	38,543	67	275,787	532

Figure 76. Commercial Electric HWH Operating Coincidence Demand



We did not pursue this as a solution set candidate based on several considerations, including:

- We are uncertain of commercial water heating duty cycle and could not define what percentage of technical load is coincident with winter morning peaks. We suggest this be a topic of any potential commercial end use study (CEUS).
- We consider that CBECS is a reasonable basis to estimate the number of buildings with CHWH but are uncertain about the number of units installed and distribution of tank sizes. We suggest this also be a topic of any potential commercial end use study (CEUS).
- We are not aware of any third-party DSM aggregators that are active in this market and that might be able to deliver a hot water solution like that proposed for the residential market. Aggregators would likely offer the most efficient method of capturing this potential. However, it is likely aggregators will enter this market because of its growth (Figure 71) and the technology solutions used in the residential market, either switch or rate enabled, are maturing and will be viable for commercial applications.

We consider this market worth monitoring because turnover of electric resistance hot water heaters is high, and volumes are large. Electric hot water heaters have an average useful life of around 10 years, indicating that around 27,000 units are replaced each year based on the estimated number of installed units defined in Table 43.

Solution Set Recommendations

Based on the proceeding analysis, this section defines our modelling inputs and expected 10-year savings trends for the following solution set components:

- Bring Your Own Thermostat (BYOT) and Rate Enabled Thermostats (RET), collectively referred to as controlled thermostat measures.
- Automated Demand Response (ADR) for larger C&I flat rate customers selecting advanced rates
- Winter Heat Pump Tune-up (mention but need CEUS to forecast)

Like the discussion on the residential solution set, the following discussion provide a summary of these solutions and related modelling inputs that are explained more fully in the separate report on Task 4 of our scope, Prepare Winter Peak Targeted DSM Plan.

Bring Your Own Thermostat (BYOT) and Rate Enabled Thermostats (RET)

BYOT and RET would be implemented via the DEP EnergyWise for Business Programs[43]. We modelled the demand response for BYOT and RET as a single, combined impact and used common modelling inputs that have a similar operational sequence to the residential BYOT recommendation but have a slight variation in duration, including:

- 1-hour preheat beginning at hour starting 6:00
- 3-hour events from hour starting 7:00 through hour starting 9:00. We expect decreasing yields in hours starting 8:00 and 9:00
- 2-hour recovery from hour starting 10:00 through hours starting 11:00

During the 3-hour event, some systems will turn back on if the facilities cannot maintain an acceptable temperature and as such, savings degrade through hours starting 9:00, as shown in Table 44. After the event, a 1-hour recovery period is expected during which the heating system activates to return the indoor temperature to settings determined by the occupant. Our estimated max site yield is 2.88 and

[43] Listed as the SBEEDR program in the DSM snapshot presented in Table 3

2.90 kW for DEC and DEP respectively and assumes a 75% cycle based on the evaluation of the EnergyWise Business program.[44] We are aware of disappointing impact results defined in the SPEEDR evaluation but suggest that 1) customers on a TOU rate may be more amenable to a longer event duration and 2) any new program exclude 25% and 50% cycle options.

Table 44. Hourly Commercial BYOT and RET kW Impacts per Participant

Hour Starting	Impact Curve	DEC	DEP
5	0%	0.00	0.00
6	-82%	-2.36	-2.38
7	100%	2.88	2.90
8	55%	1.59	1.60
9	41%	1.18	1.19
10	-100%	-2.88	-2.90
11	-14%	-0.40	-0.41

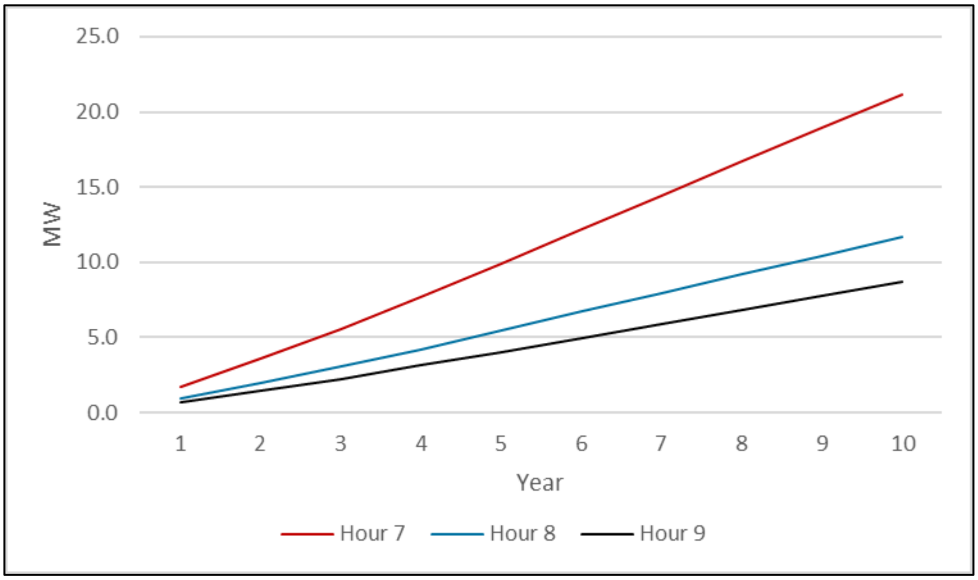
Figure 72 shows the forecast by hour over a 10-year horizon based on the following assumptions for the combined C&I BYOT and RET offering:

- 1st year market adoption of 1.00%
- Annual program growth 7%
- Operating coincidence 18%
- Starting year 1 participation: 2,624 HP units
- Start Year: Dec-20

As shown in Figure 74, at the end of a 10-year implementation period we expect a peak load shed capacity of approximately 21 MW during the hour starting at 7:00, declining to 8 MW by the hour starting at 9:00. The 1-hour preheat and 2-hour recovery period result in neutral energy use during the 6-hour total event.

[44] Duke Energy Carolinas and Progress EnergyWise Business Evaluation Report, Final. Opinion Dynamics, November 9, 2018

Figure 77. 10-Year Controlled Thermostat Savings Forecast by Hour



Automated Demand Response

As discussed in the solutions set defined for the large C&I market, Automated Demand Response (ADR) combines advanced rate design with technology to enable robust demand response. We consider this a viable solution for medium sized C&I customers and included the impacts for medium sized C&I participation in the ADR forecast provided for the large C&I segment.

Solution Set Measures Considered but Not Forecast

The following measures were considered for analysis but not pursued at this time.

1. Winter Heat Pump Tune-up. We expect that the same winter heating tune-up program being recommended for the residential market applies to the commercial market, though we did not analyze the potential because of uncertainty about the performance of installed commercial heat pumps.

2. Electric Hot Water Heating. As presented in the C&I Market Characteristics discussion, we consider the electric hot water heating market worth monitoring and recommend the following research:

   - Complete a CEUS defining:
     - Commercial water heating duty cycle and define the technical load that is coincident with winter morning peaks
     - Define segmentation including the number of units installed and the distribution of sizes across each segment
   - Complete an assessment of the market delivery capacity of local trade allies and distributors to deliver and install heat pump water heaters.
   - Identify any third-party DSM aggregators operating or emerging that will be delivering an integrated commercial water heater DSM solution.

6. Large C&I Market and Solutions

Rate Definitions

For this analysis, we define the large C&I segment as high demand customers participating in DEC's optional TOU and DEP's RTP rates. Some of the solutions presented here may also apply to medium sized C&I costumers and the rates we defined for this segment in section 5 at Table 36. During the average winter peak day in 2018, large C&I customers accounted for about 32% of combined DEC and DEP system demand. Table 45 provides a summary rates for the large C&I sector and shows that during our study peak day event DEC customers account for 86% of large C&I demand while DEP customers account for the remaining 14%.

Table 45. Large C&I Rates Summary

System	Schedule	Tier Type	On Peak	Winter	Study Peak Day MW	% Load	KW Cap
DEC	OPT-E (NC - Pilot)	On/Off kWh	6:00 a - 1:00 p	Oct – May	4,232	86%	Tiered
	OPT-V (NC)	On/Off kWh and KW	6:00 a - 1:00 p	Oct – May			
DEP	LGS-RTP-58	RTP Hourly Energy Charge	None	None	668	14%	>1,000

Peak Load Profile

The following section provides observations for DEC and DEP load profiles based on a review of 8,760 hourly load data for the C&I rates defined in Table 45. The analysis of DEC optional TOU rates (OPT-E and OPT-V (NC) in Table 45) have been refined to disaggregate between commercial (Opt-C) and industrial (Opt-I) TOU customers.

DEC

Figure 75 compares the average demand from Opt-C and Opt-I for the 6 winter and 4 summer peak events in 2018 and shows a relatively constant profile, with increased usage in the summer likely due to 1) increased air conditioning loads, and 2) increased process loads, such as increased water transfer. The limited winter peak indicates that many of these customers have access to natural gas for heating. Figure 76 separates Opt-C and Opt-I for the 6 winter events and shows a difference in profiles such that Opt-C more closely resemble a commercial profile. We note that, in aggregate, these facilities have long run hours, maintaining a near constant load throughout the average winter peak day.

Figure 78. DEC 2018 Large C&I – Average Season Peak Day

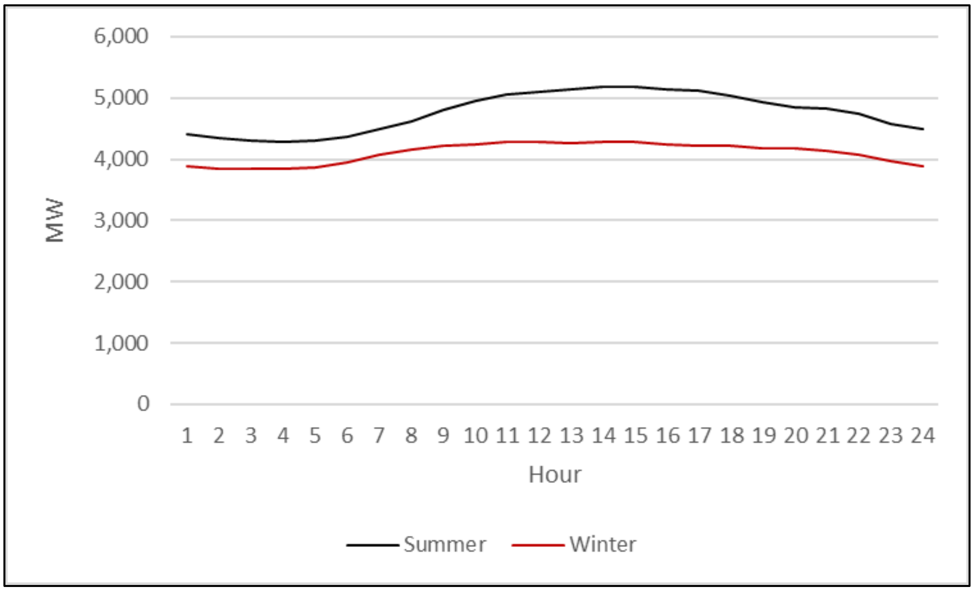


Figure 79. DEC 2018 Large C&I - Study Peak Day

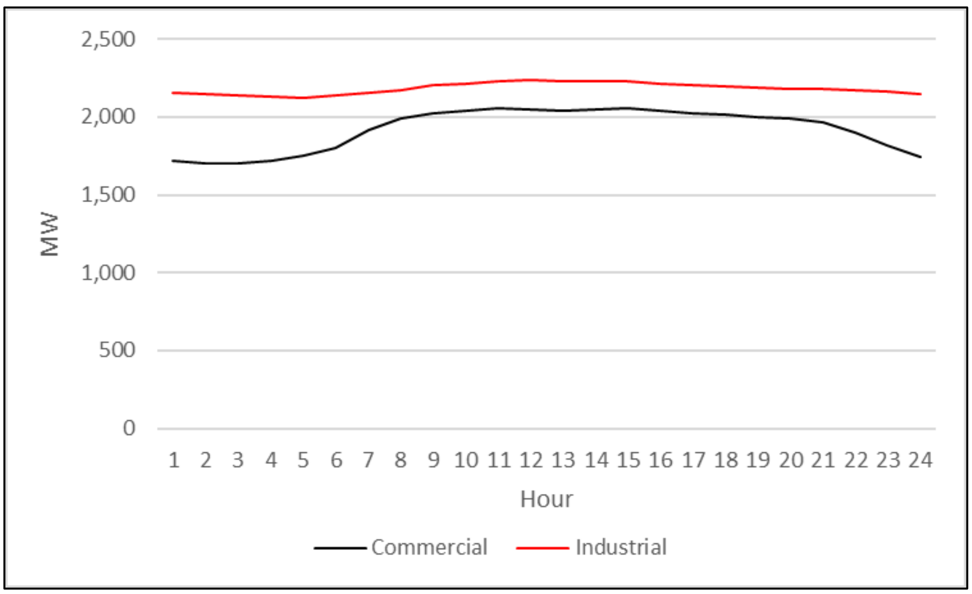


Figure 77 looks at the study peak day and adjusts the scale to emphasize the difference in load shapes between commercial and industrial TOU customers. We analyzed the underlying data and estimate that the heating load attributable to Opt-C customers is 155 MW by comparing average demand of 2,108 MW during the hours ending 7 through 9 with the average demand for hours ending 1 through 6 and 10 through 24 (1,947 MW across all non-peak hours), as shown in Table 46.

Table 46. DEC Optional TOU Commercial Demand – Study Peak Day

Time Period	Average MW
Hour ending 1 through 6 and 10 through 24	1,947
Hour ending 7 through 9	2,103
Difference	155

Figure 80. DEC C&I Optional TOU Rate Demand by Segment – Study Peak Day

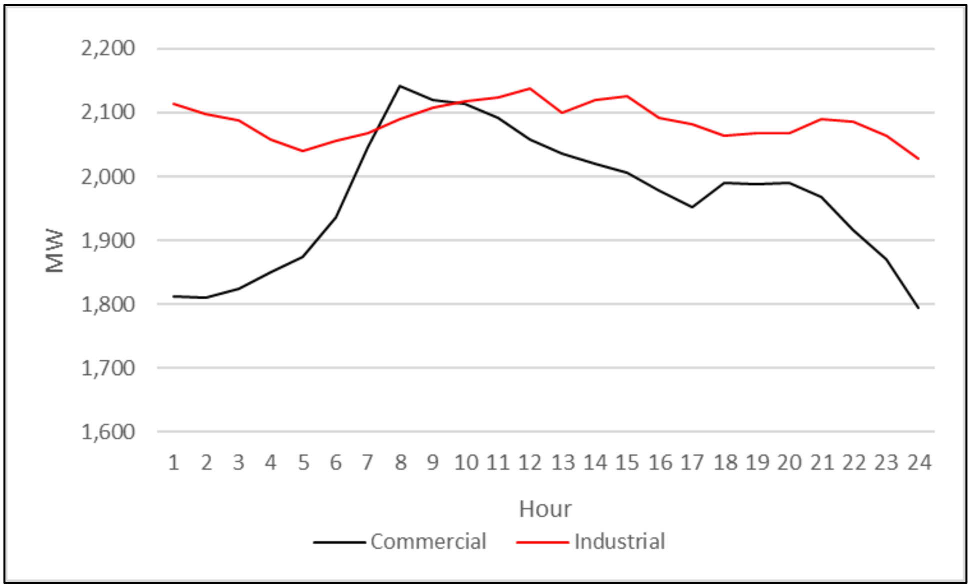


Figure 77 compares demand between the study peak day and the average winter peak days for Opt-C customers, showing a difference of about 130 MW between hours 7:00 and 8:00, indicating that these customers have demand associated with heating that is moderately sensitive to weather events.

Figure 81. DEC Optional Commercial TOU Rate Demand – Study Peak Day Vs. Average Winter Peak Day

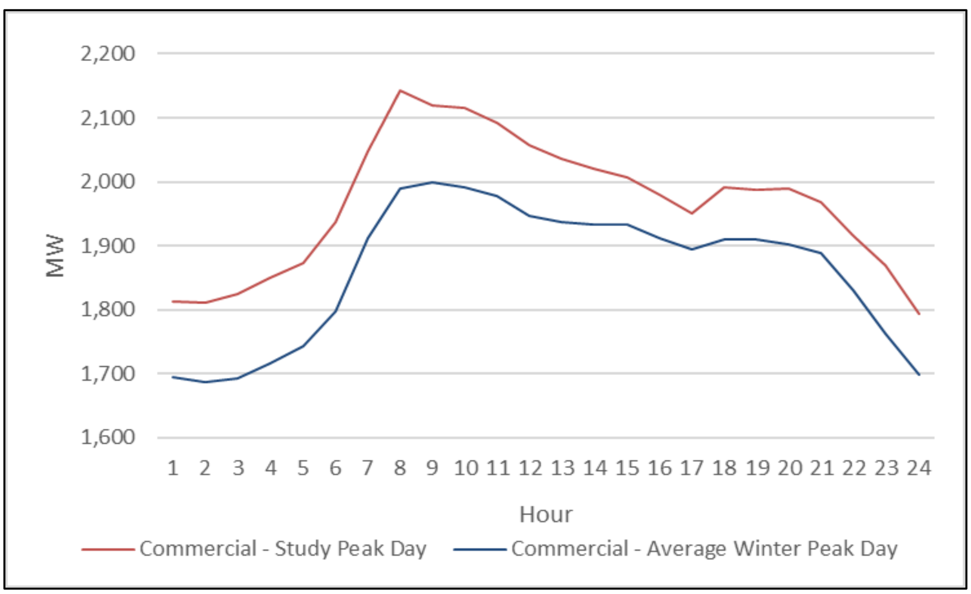
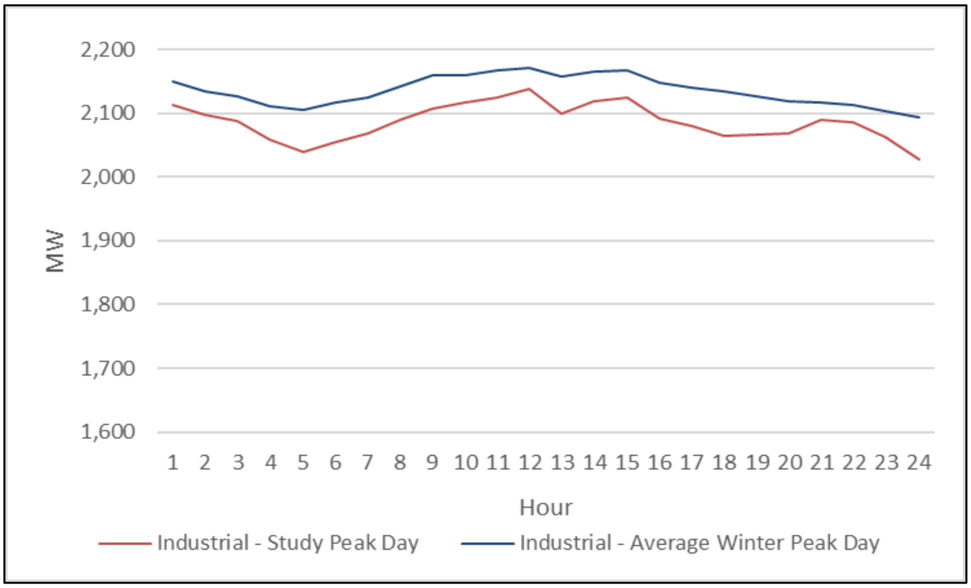


Figure 77 compares demand between the study peak day and the average winter peak days for Opt-I customers, showing slightly lower usage during our study peak day when compared to the average winter peak day, indicating that these customers may not be sensitive to weather events.

Figure 82. DEC Optional Industrial TOU Rate Demand – Study Peak Day Vs. Average Winter Peak Day



DEP

No segmentation data was provided for the LGS-RTP-58 rate and thus we were unable to compare industrial and commercial customers. As observed for the DEC optional TOU customers, Figure 79 shows an increase in summer demand most likely related to commercial AC loads and industrial production.

Figure 83. DEP 2018 Large C&I – Average Season Peak Day

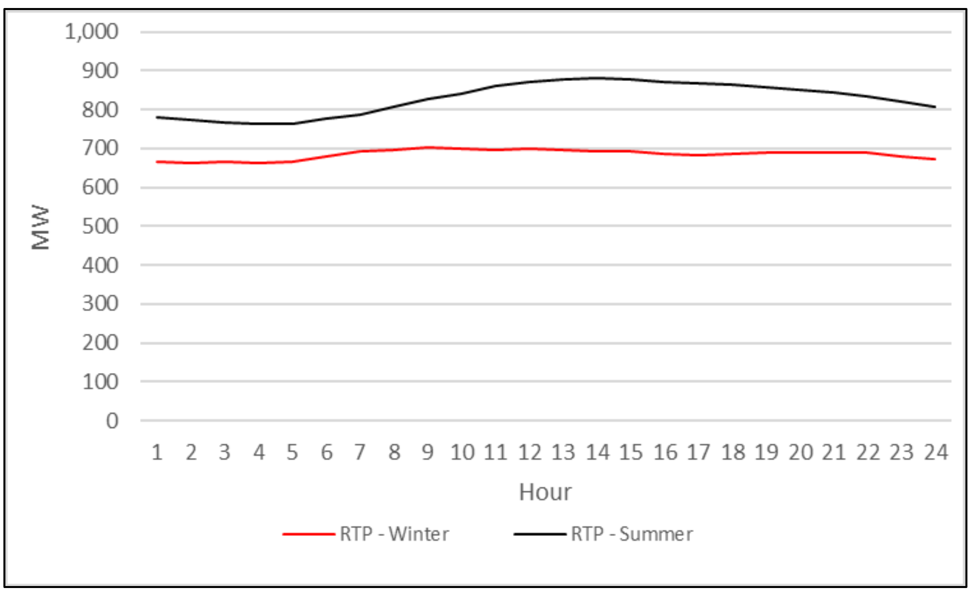


Figure 80 looks at the study peak day and adjusts the scale to emphasize the load shape profile during our study peak day, showing peak demand between 7:00 a.m. and 11:00 a.m., indicating some heating load. Like DEC, we analyzed the data underlying Figure 80 to define a heating load of 41 MW as shown in Table 47 .

Figure 84. DEP 2018 RTP Demand – Study Peak Day

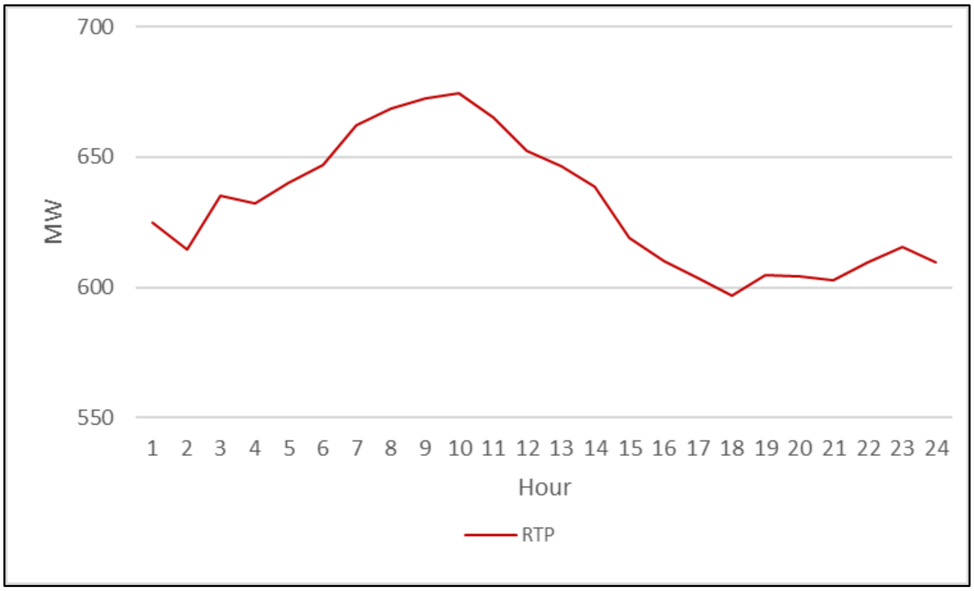


Table 47. DEP RTP Demand – Study Peak Day

Time Period	Average MW
Hour ending 1 through 6 and 10 through 24	626
Hour ending 7 through 9	668
Difference	41

Market Characteristics

Because we have limited segmentation data, our capacity to characterize the large C&I market is limited to interpreting information from various secondary sources. Table 48 provides an additional analysis of CBECS building population data first presented in Table 42 to estimate the number of large C&I buildings. It estimates that the number of buildings larger than 30,000 sq. ft. which would be applicable to large C&I solutions is approximately 57,000 across both utilities. This analysis excludes market segments where it is unlikely that any building would exceed 30,000, such as restaurants. As discussed at Figure 75, many of these buildings will be heated with natural gas, but all have curtailable winter loads from lighting and HVAC ventilation systems, with additional AC loads available in the summer.

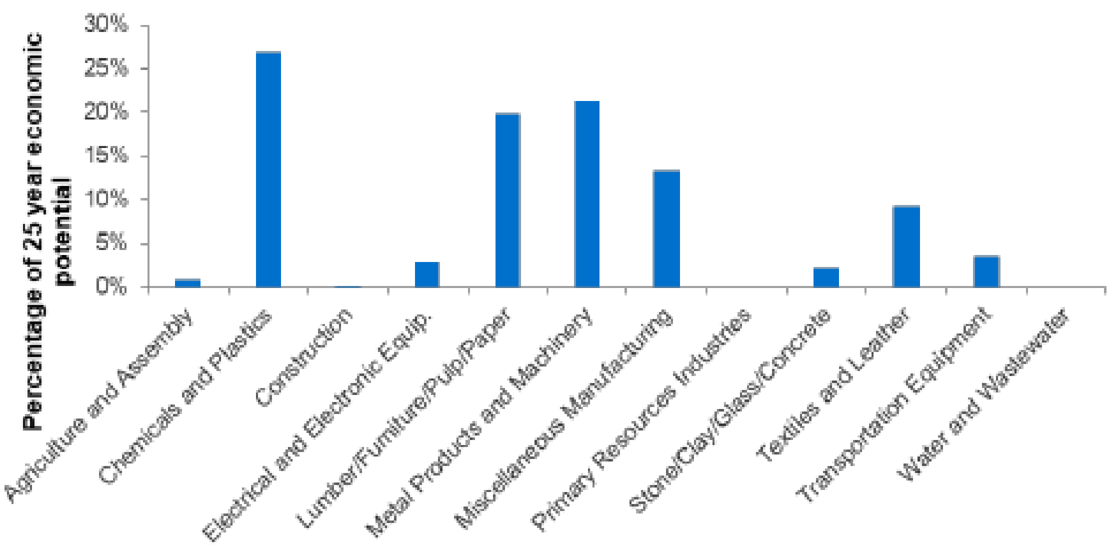
Table 48. Estimated Population of Large Buildings by Segment

	Total Buildings			Buildings > 30,000 sq ft		
Segment	DEC	DEP	Total	DEC	DEP	Total
Education	9,450	5,964	15,414	4,725	2,982	7,707
Food sales	4,345	2,742	7,087	434	274	709
Health care Inpatient	155	98	253	109	69	177
Health care Outpatient	2,281	1,440	3,721	456	288	744
Lodging	3,584	2,262	5,847	1,792	1,131	2,923
Mercantile Retail	9,993	6,307	16,300	1,999	1,261	3,260
Mercantile Enclosed Mall	5,540	3,496	9,036	2,770	1,748	4,518
Office	21,506	13,574	35,080	10,753	6,787	17,540

Public assembly	4,888	3,085	7,973	2,444	1,542	3,986
Public order and safety	1,700	1,073	2,773	1,020	644	1,664
Warehouse and storage	19,225	12,134	31,359	7,690	4,854	12,544
Other	1,847	1,165	3,012	923	583	1,506
Total	112,537	71,026	183,563	35,115	22,163	57,278

For industrial loads we reviewed the Nexant Market Potential Study[45], and Figure 82 and Figure 83 show energy efficiency potential by industrial segment for DEC NC and DEP SC. Segment potential varies by state and system but can be viewed as a reasonable proxy indicator of segment level demand sources in the industrial market because, in general, all segments have similar equipment and energy efficiency potential. For example, Figure 84 shows energy efficiency potential by end use for DEP NC, and this distribution is consistent across the MPS studies for both states and utilities. Because energy efficiency potential in the industrial sector is also an indicator of the primary sources of load, Figure 84 indicates that demand response potential is most likely concentrated in motors, pumps, and HVAC systems (which we interpret to include refrigeration).

Figure 85. DEC NC Industrial EE Economic Potential by Segment[46]



[45] Duke Energy North Carolina EE and DSM Market Potential Study, Nexant, May 2020

[46] Duke Energy NC Carolina EE and DSM Market Potential Study. Nexant, May 2020. Figure 6-5: DEC Industrial EE Economic Potential by Segment

Figure 86. DEP SC Industrial EE Economic Potential by Segment[47]

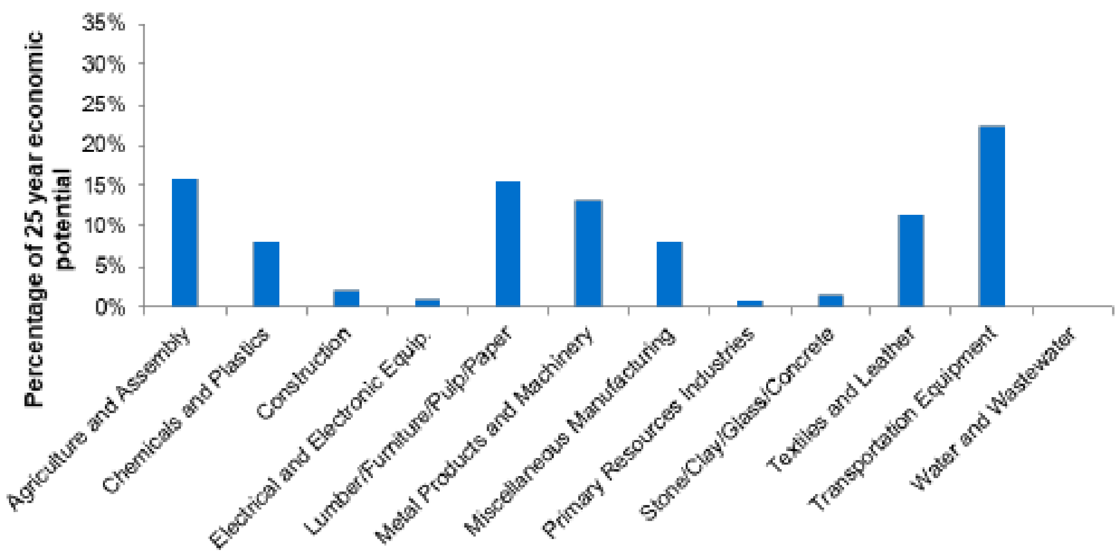
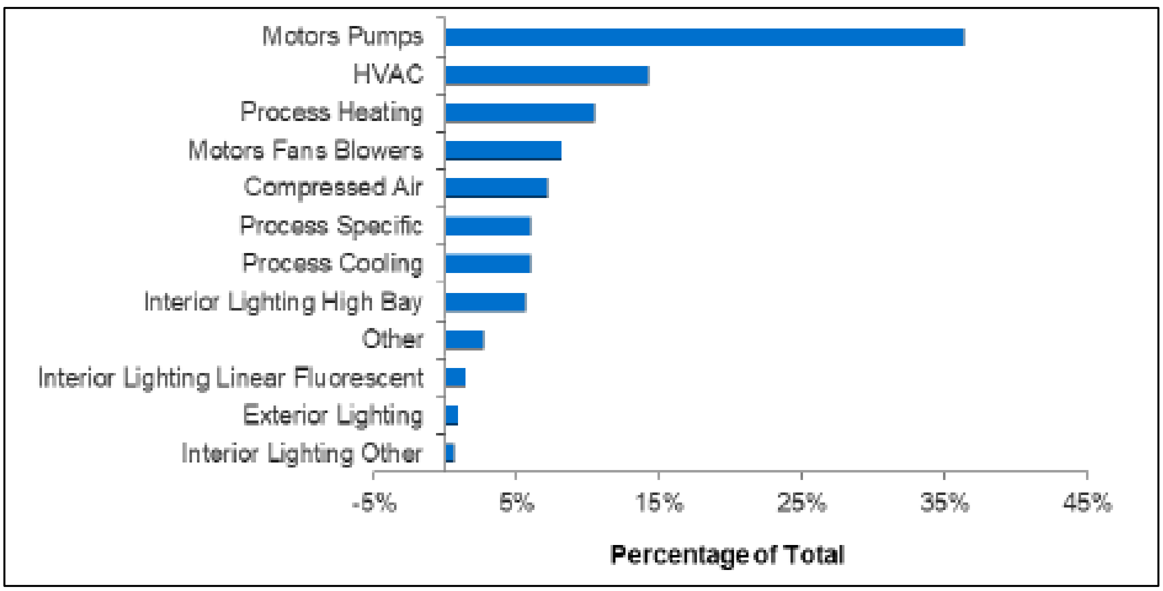


Figure 87. DEP NC Industrial Baseline Load Shares[48]



Solution Set Recommendations

Based on the preceding discussion, the following provides key recommendations for the large C&I solution set.

[47] Duke Energy SC Carolina EE and DSM Market Potential Study. Nexant, May 2020. Figure 6-10: DEP Industrial EE Economic Potential by Segment

[48] Duke Energy North Carolina EE and DSM Market Potential Study. Nexant, May 2020. Figure 3-12: DEP Industrial Baseline Load Shares

ADR Program Concept

As discussed throughout the large C&I DSM Capacity section, Duke's DSM solution for large C&I customers relies mostly on the use of customer sited backup generation and process interruptions which suffer from the following shortcomings:

- The backup generation market is limited and may not be growing as industrial loads decline, and potential that may exist is likely to have been recruited through the legacy and EE rider programs in operation over the past decade. This potential is also at risk because it is subject to regulatory constraints outside of Duke's control.
- DSM capacity related to production interruptions and responses from one event to the next can vary because it is unlikely to respond during multiple concurrent days, such as a polar vortex. In addition, this resource is generally restricted to use only in grid emergencies and our impression is that these are called infrequently.

The following describes an Automated Demand Response (ADR) program (Program) structure that we expect is applicable to medium and large C&I programs in the Carolinas and which is based on programs in operation in California's three electric investor-owned utilities[49] since 2014. The objectives of the Program, as discussed in more detail further in the document, include:

- Fill gaps in the current C&I DSM offering
- Diversify the DSM resource mix and improve reliability
- Reduce opt-outs by expanding the DSM value proposition
- Reduce participant attrition
- Leverage emerging Duke data infrastructure to manage DSM operation costs
- Increase DSM cost recovery
- Expand both summer and winter demand response capacity
- Provide a pathway for emerging technology adoption

For background, California's ADR programs are locationally dispatchable and involve a combination of innovative rates, programs, and technology solutions where customers may choose from among different options designed to fit their needs. The intent of the ADR solution is to provide the utilities with 1) the kW for projects receiving ADR incentives to be as realistically achievable as possible, and 2) customers that will participate consistently in as many DR events as possible. Below are rates and program solutions that California ADR customers may participate in, by utility:

Pacific Gas and Electric (PG&E)

- Peak Day Pricing (PDP) Tariff / Rate
- Capacity Bidding Program (CBP)
- Demand Bidding Program (DBP)

Southern California Edison (SCE)

- Real Time Pricing (RTP) Tariff / Rate
- Critical Peak Pricing (CPP) Tariff / Rate
- Demand Bidding Program (DBP)
- Aggregator Managed Portfolio Program

[49] Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E)

- Capacity Bidding Program (CBP) Program
- Demand Response Auction Mechanism (DRAM) Pilot DR Program

San Diego Gas and Electric (SDG&E)

- Peak Time Rebate (PTR) Tariff / Rate
- Base Interruptible (BIP) Program
- Capacity Bidding (CBP) Program

Regarding technology solutions, participants must have, or install, equipment that can be controlled remotely, such as an EMCS or other control. The ADR programs provide incentives and technical assistance for medium to large nonresidential customers to install and/or program equipment at the customer's facilities. The objective of this program is to enable the execution of a sequence of steps at the facilities to curtail electrical load after receiving a communications signal from the utility via the OpenADR communications protocol with the objective of maximizing the reliability and consistency of available kW capacity. In general, business customers can choose from equipment incentives that enable the following DR strategies:

- Global temperature adjustment: Existing energy management control systems (EMCS) were adjusted to receive the DR event signal from the DRAS. Once that signal was received, the EMCS would raise the setpoint temperature established by a customer (usually in the range of two to eight degrees) for a period of time.
- HVAC equipment cycling: For buildings with multiple packaged HVAC systems, select units were configured to receive the DR event signal from the DRAS. Once that signal was received, compressor units were shut off for a subset of the building's systems during an acceptable period of time. Additional signals were then sent to restart those units and shut off other units.
- Other HVAC adjustments: Other HVAC shed strategies included decrease in duct pressures, auxiliary fan shutoff, pre-cooling, valve limits and boiler lockouts.
- Light shutoff or dimming: Various lighting circuits were wired to receive the DR event signal from the DRAS. When signaled, these loads would be tripped or dimmed for the entire duration of the DR event. Typically, these were for lighting applications in common areas with sufficient natural light or for task applications that could accommodate full shutoff given the proximity of other lighting in the area.
- Other lighting and miscellaneous adjustments: Other shed strategies that were employed included bi-level lighting switches and motor/pump shutoff.
- Process adjustments: Given the varying nature of industrial processes, the strategy for each customer was tailored to their particular process. The most common ADR strategy employed was modifying ancillary processes where there is sufficient storage capability such that the customer can accommodate complete equipment shutdowns during DR events and catch-up production later in the day or the following day.

The ADR program requires that customers have an OpenADR 2.0 A or B certified virtual end node (VEN) on site that pulls the automated DR event signal directly from a utility or aggregator. The ADR architecture consists of two major elements built on an open-interface standards model called OpenADR. First, the Demand Response Automation Server (DRAS) provides signals that notify electricity Participants of DR events. Second, a VEN or client for each Participant's site continually communicates with the DRAS and is linked to existing preprogrammed DR strategies independent of control network protocols such as BACnet or Modbus. Legacy ADR control systems used a VEN called a Client and Logic with Integrated Relay (CLIR), but these devices are no longer manufactured.

During a DR event with fully automated DR, the facility equipment receives a signal from the utility directly, and executes load shed strategies without Participant intervention. The technology solution consists of an open, interoperable industry standard control and communications technologies designed to work with both common energy management control systems and individual end-use devices. The technologies include a communications infrastructure via a computer server that sends DR signals to PG&E's Participant sites where load reductions are automatically implemented through building control systems. The technology and communications infrastructure used in ADR originated from an initial conceptual design developed in 2002 at Lawrence Berkeley National Laboratory (LBNL). ADR is a fully automated DR system using Client/Server architecture and is intended to replace labor-intensive manual and semi-ADR.

Objectives

The ADR program concept applied to the Carolinas is intended to address the following objectives.

Fill Gaps in the Current C&I DSM Offering

This program focuses more on the commercial segment where most controllable loads are HVAC and lighting related much of which is coincident with system peak. As shown in Figure 84, demand from commercial customers on the optional TOU rates (Opt-C) are about 90% coincidence in the 7:00 to 9:00 a.m. system peak timeframe.

These C&I lighting and HVAC assets are not present in the current DSM portfolio. At present, the bulk of system C&I DSM capacity is associated with 1) process related curtail at large industrial customers and 2) the use of customer owned backup generation during peak events as shown in Table 49. Most of this current capacity can be associated with industrial customers, such as DEC the optional TOU rates for industrial customer (Opt-I), also shown in Figure 84. The proposed ADR program will address this gap by targeting commercial lighting and HVAC assets.

Figure 88. DEC 2018 Optional TOU Prototype Winter Event Demand by Segment

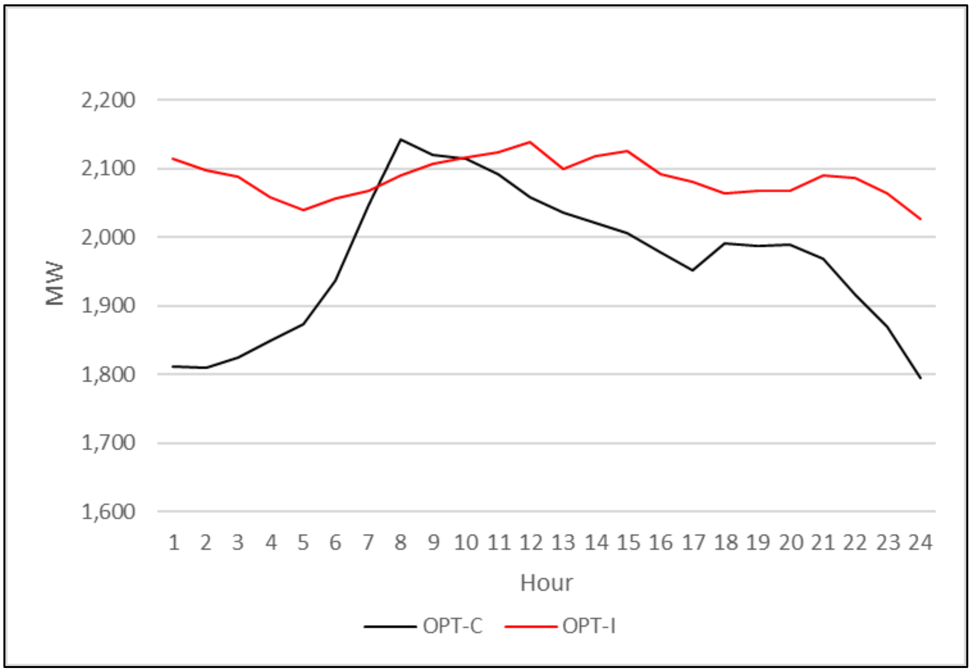


Table 49.DSM Capacity for PS and DRA

Primary Load Reduction Source	Participants	Capacity (MW@mtr) Summer	Winter	Ave Winter MW / Part
PowerShare				
Generator	55	66.9	67.3	1.2
Process	109	281.4	261.3	2.4
HVAC/Lighting	0	0.0	0.0	0.0
PowerShare Total	164	348.3	328.6	2.0
DRA				
Generator	41	16.6	11.7	0.3
Process	36	8.5	3.0	0.1
HVAC/Lighting	11	0.7	0.0	0.0
DRA Total	88	25.8	14.7	0.2
Combined				
Generator	96	83.5	79.0	0.8
Process	145	290.0	264.3	1.8
HVAC/Lighting	11	0.7	0.0	0.0
Combined Total	252	374.1	343.2	1.4

Diversify and Expand the DSM Resource Mix

Our expectation is that DSM based on a portfolio of distributed HVAC controls (and other non-process related loads) will present a larger population of candidate sites and more consistent response than generation and process related resources currently distributed across a small number of customers. Table 50 shows approximately 100% of DSM capacity is associated with generators and process curtailments from 252 DRA and PS customers defined in Table 49. Table 51 shows our preliminary estimate of 26,000

ADR viable sites[50] out of a total 66,000 customer sites across various rate classes reviewed, which forms the basis of an ADR solution focusing on EMCS controls, which currently make up less than 0.2% of combined PS and DRA capacity.

Table 50. PowerShare and DRA Capacity Allocation by Load Reduction Source[51]

Primary Load Reduction Source	OPCO - Program		System	
	DEC - PS	DEP - DRA	DEC	DEP
Generator	20%	80%	20%	3%
Process	80%	20%	76%	1%
HVAC/Lighting	0%	0%	0%	0%
Total	100%	100%	96%	4%

Table 51. Estimate of ADR Viable Customers by Rate Class

OPCO	Rate	Customers		
		Total Customers	% Viable	Viable Customers
DEC	LGS	11,431	40%	4,572
	OPTC	21,133	40%	8,453
	OPTI	1,642	10%	164
DEP	MGS	32,108	40%	12,843
	LGS	345	40%	138
Total		66,659	39%	26,171

Expanding the DSM Value Proposition

Based on data provided by Duke, Table 52 provides our analysis of EE/DSM opt-out rates for various DEP rate classes. This data indicates that a large number of medium sites may be available for an ADR solution, but for most there is currently no viable DSM option because most will not have backup generation capacity, which is the only way they could meet the DRA and PS curtailable load thresholds.

We're uncertain why opt-out rates are so high for larger customers, but this may indicate that the current DSM offerings are not attractive and that combining Advanced Rates with technology solutions may provide a more attractive offer for some of these customers. The value proposition for an ADR solution will likely vary by market segment, and this should be reviewed and defined. For example Appendix 1, Public Segment DSM Value, provides an overview of the value on DSM in the public market segment and how ADR could be leveraged in this market, and Appendix 2, Water Treatment Segment DSM Value, discusses how DSM is applied in the water treatment market and indicates how ADR might be applied to existing SCADA systems at these facilities.

Table 52. DEP Opt-out by Rate Class[52]

Rate Class	Opt Out	Accounts	% Opt-out
SGS	4,413	183,637	2%
MGS	684	19,713	3%
LGS	212	214	99%

[50] Customers over 30,000 sq. ft. controllable via access to EMCS system
[51] KEY FILE - PowerShare and DRA Participant Info - July 2020 2020.07.07
[52] KEY FILE - DSM EE Opt Out_Apr20_Floyd (version 1).xlsb

LGS-RTP	90	80	113%

Reduce Participant Attrition

Between 2015 and 2020, many of Duke's DSM solutions have experienced attrition, including:

- Many of Duke's legacy DSM programs, such as Large Load Curtailable, have seen decreases in available load for various reasons such as decreasing textiles industrial base or dropping off the programs because of difficulty curtailing production related loads during extended events.
- Between 2015 and 2020, PS and DR have seen 140 MW of attrition, resulting in a net decrease of 24 MW after new additions are considered. This includes 59 MW of capacity lost due to shifts in EPA rules regarding the use of backup generation for grid dispatch purposes, as shown in Table 53.

Table 53. Summary of DRA Participation by Sector[53]

Program	PS	DRA
Total 6-Year MW Attrition	(130)	(10)
Net 6-year MW Attrition	(31)	7
6-year EPA MW Attrition	(49)	(10)
EPA Attrition	44%	72%
Non-EPA Related Attrition	56%	28%

We expect that providing ADR solutions that leverage automated EMCS controls will have low attrition rates because they will have minimal, if any, impact on operations beyond slight adjustments to HVAC and lighting loads. Additionally, they will not have an impact on production related machines and are unlikely to be subject to any future EPA, or other, regulatory action.

Leverage Emerging Duke Data Infrastructure to Manage DSM Operation Costs

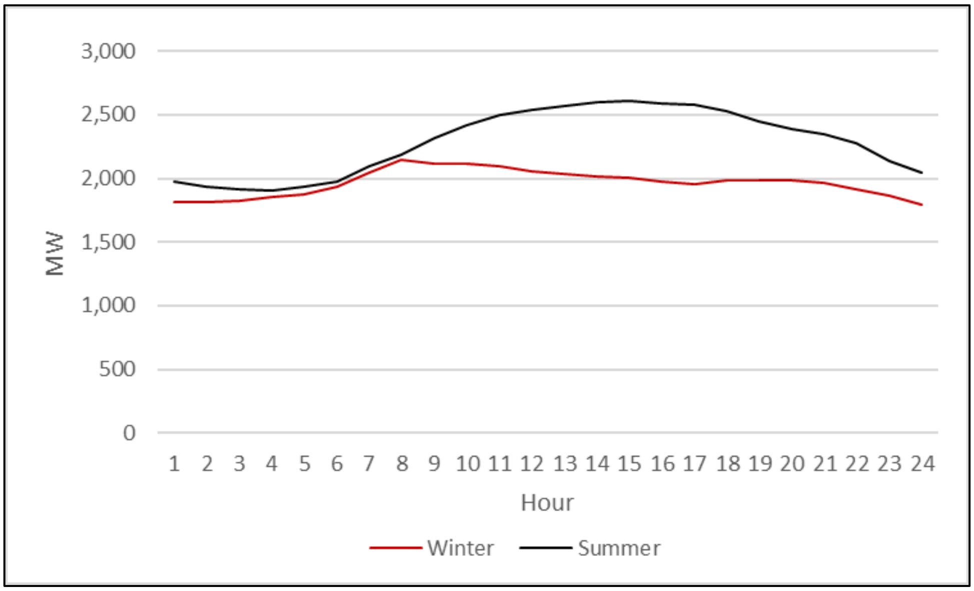
The proposed ADR design leverages Duke's expanding AMI and CIS/customer analytic capacity. This may help lower program costs in several ways, thereby enhancing cost effectiveness, including reducing the cost of identifying high potential sites and the use of normalized metered energy consumption to reduce EM&V costs.

Expand Both Summer and Winter Demand Response Capacity

The technologies associated with ADR are applicable to both summer and winter peak events. For example, while our efforts have focused on winter peak, Figure 86 shows that summer peak for the DEC commercial customers on optional TOU rates is more pronounced, likely because many of these customers have natural gas heating, but all will have electric powered mechanical cooling systems. The objective of developing EMCS systems for winter peak ADR will likely have a larger impact on summer DR capacity. Based on Figure 86, we anticipate that summer ADR potential related to EMCS impacts on air conditioning will be roughly 40% higher than winter heating potential.

[53] 2016 EM&V Report for the Duke Energy Progress Commercial, Industrial, and Governmental Demand Response Automation (DRA) Program. Navigant. June 19, 2017

Figure 89. DEC 2018 Optional TOU Demand for Average Season Peak Events



Provide a Pathway for Expanded Use of Existing and Emerging Technologies

ADR programs offer opportunities to deploy DR-focused emerging technologies that might be applicable to the Carolinas that are not currently represented in Duke's solution portfolio, including technologies defined in SDG&E Demand Response Emerging Technologies Program:[54]

1. **Battery Powered Load Shedding System.** The objective of this study is to evaluate the DR capability of the Energy Storage System (ESS). In addition to peak load shaving capability, the study will evaluate the impact of the energy storage system on the circuit and analyze customer bill/economic impacts.
2. **Vehicle to Grid Integration Platform (VGIP)**. The purpose of VGIP is to create requirements and use cases for a unified grid services platform that is secure, low cost, and an open platform. It will also aide in the development of architecture and functionality of the VGIP including OpenADR2.0b, SEP, and Home Area Network (HAN). Additionally, this project will assess performance of the VGIP against utility requirements through field tests and trials. BMW, Chrysler, Ford, GM, Honda, Mercedes, Mitsubishi, Nissan, and Toyota have agreed to be study participants.
3. **Demand Response with Variable Capacity Commercial HVAC System**s. Variable Capacity systems, with their onboard instrumentation and communications capabilities, are candidates for implementing both EE and DR measures at the same time. Efficiency rebates have been in place for such equipment in certain areas, but DR capabilities can push the technology further into the mainstream market, which is dominated by rooftop units, split systems and chiller/boiler combos. Commercial HVAC systems being a coincident load (peak power draw occurs during the hottest days) is a prime candidate for DR solutions besides being an efficient technology during normal operation.
4. **Permanent Load Shifting Evaluation of a Refrigeration Battery**. The Project will demonstrate the Refrigeration Battery's ability to maintain the desired temperature set-points of a supermarket's medium temperature refrigeration systems without running the central compressors or condensers for up to 8 hours at a time. By turning off medium temperature refrigeration compressors and

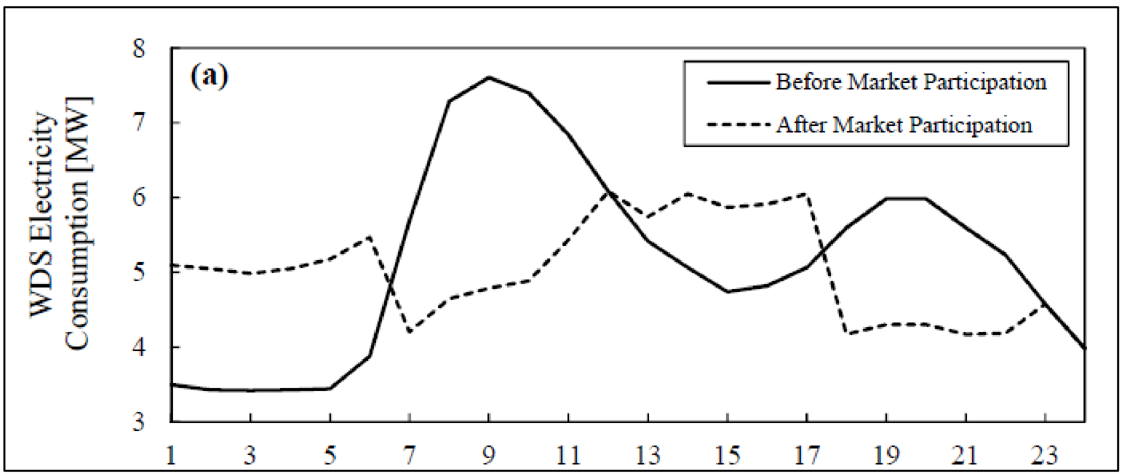
[54] 2018 SDG&E Demand Response Emerging Technologies Program semi-annual report accessed June 2020 at https://www.sdge.com/sites/default/files/regulatory/SDGE%20Semi%20Annual%20DR%20Emerging%20Tech%20Report%202018Q3.pdf

condensers during "on-peak" hours, as defined by SDG&E's AL-TOU rate schedule, the Refrigeration Battery is expected to reduce the facility's monthly peak demand by up to 75 kW. If successful it would achieve a decrease in monthly peak demand of up to 25%.

In addition to emerging technologies, ADR solution may provide for expanded opportunities with existing customers, for example:

- While much DSM was lost in the water treatment sector due to changes in EPA regulations, studies have identified substantial DR capacity by modifying pump schedules to maximize DR and economic value, much of it occurring during morning peak periods as illustrated in Figure 87.[55] ADR potential in this sector would be achieved by integrating ADR operations with existing Supervisory Control and Data Acquisition (SCADA) systems in place at each water treatment facility. Our preliminary research identified 210 water treatments in NC and SC which may be candidates. Past DSM efforts at these facilities focused on accessing back-up generation capacity only, while integrating pump loads provides a separate opportunity that is unlikely to be impacted by EPA regulations.

Figure 90. Example of Water Treatment DR Capacity Related to Pump Controls



- Microgrids are being acknowledged as potential platforms to deliver ADR capacity. Research is indicating the implementation of DR programs in MGs leads to enhancing the MG reliability as well as managing the intermittent impacts of renewable energy sources as shown in Figure 88 and Figure 89, which define shed potential for microgrids employing technology solutions coupled with TOU and RTP rates, respectively.[56]

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[55] Optimal Demand Response Scheduling for Water Distribution System. IEEE Transactions on Industrial Informatics, February 2018. Accessed June 2020 at https://www.researchgate.net/publication/322906865_Optimal_Demand_Response_Scheduling_for_Water_Distribution_Systems

[56] Demand Response Modeling in Microgrid Operation: a Review and Application for Incentive-Based and Time-Based Programs, June 2018 accessed July 2020 at https://www.researchgate.net/publication/326031387

Figure 91. Shaved Curve of Load After TOU Implementation on an 11-bus MG

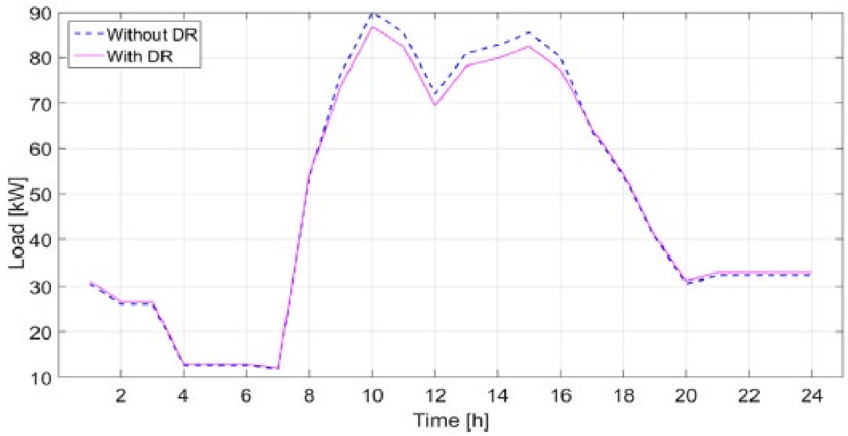
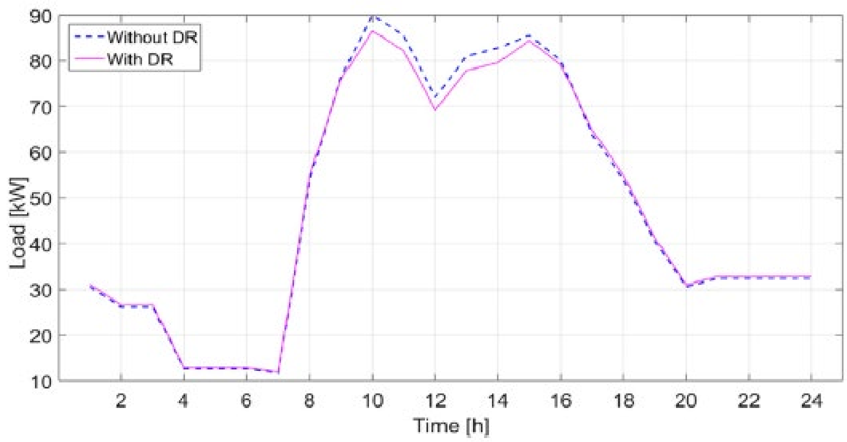


Figure 92. Shaved Curve of Load After RTP Implementation on an 11-bus MG



Key ADR Barriers

The following summarize some of the key barriers regarding an ADR solution.

1. Cost-effectiveness. The cost effectiveness of minimum curtailment threshold, such as the DRA and PS minimum curtailable capacities of 50kW and 100kW, need to assess to be reviews. Additionally, the ability to recover costs on summer resources is being restricted beginning in 2021 and this may cause an ADR program to not be cost-effective
2. Requiring 3rd party aggregators. Third party aggregators will be required to implement an ADR solution and we are uncertain if various regulatory constraints, such as the inability beginning in 2021 to claim benefits for summer DSM, will allow for a cost-effective implementation.
3. Cost to aggregate meters. Historically, it has not been cost-effective to aggregate meters however this should be reviewed in the context of increased AMI deployment, decreasing cost of control technology, and 3rd party ADR service provider ability to reduce installation and administrative costs, reporting and EM&V.
4. Cost recovery rules on pilot programs. Current regulations require that the cost of failed pilot programs must be paid back, a clear disincentive for innovation.
5. High opt-out rates on larger customers. ADR would need to be funded through the EE rider and may require participation in both the EE and DSM components to achieve appropriate funding levels. ADR

would target large C&I customers and the majority of these opt-out of the EE rider, as discussed at Table 18.

ADR Modelling Inputs

Based on the proceeding discussion, our modelling inputs and expected 10-year savings trends for the ADR are based on the following assumptions:

- First year participation of large customers of 0.50% (155 total)
- Annual growth rate of 0.50%
- 80% HVAC coincidence at the hour ending at 7:00
- 90% HVAC coincidence at the hour ending at 8:00
- 100% HVAC coincidence at the hour ending at 9:00
- No preheat period and a 2-hour recovery for HVAC yielding a revenue neutral impact
- 45 kW average per site winter impact for ventilation and lighting

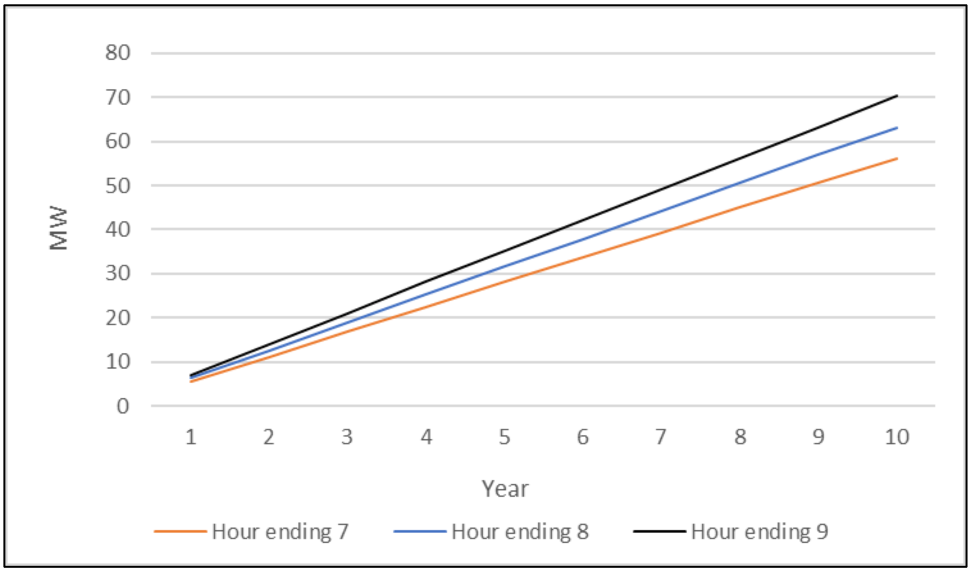
During the 3-hour event beginning at hour starting 7:00, some systems automatically adjust HVAC and light setpoints, savings will increase as facilities become more active with peak impact in hour starting 9:00. Table 54 shows our modelled ADR kW reduction occurring between 7 and 9, and likely kW increase during a 3-hour recovery period at hour starting 10. We expect ADR to be kWh neutral.

Table 54. Hourly Commercial BYOT and RET kW Impacts per Participant

Hour Starting	Coincidence	DEC	DEP
7	80%	36.28	36.28
8	90%	40.82	40.82
9	100%	45.35	45.35
10	-100%	-45.35	-45.35
11	-100%	-45.35	-45.35
12	-70%	-31.75	-31.75

Figure 90 shows the forecast by hour over a 10-year horizon, achieving a maximum impact of 70 MW in the hour ending at 9:00. Our forecast is based on 1,548 ADR participants in year 10, which represents less than 3% of our estimate of the 57,278 commercial facilities over 30,000 sq. ft, as discussed at Table 53. We did not consider industrial customer participation because of a lack of segmentation data but consider this a variable market sector.

Figure 93. 10-Year ADR Savings Forecast



Additional Large C&I Solution Set Consideration

Managed EV Charging

We reviewed commercial charging load forecasts and resulting load shapes and considered it as a long-term DSM opportunity but was omitted from our analysis based on several considerations. Figure 91 compares C&I and commercial EV charging winter peak demand profiles showing that commercial EV charging peak is at hours ending 9:00 and 10:00 and is coincident with C&I peak occurring between hours ending 9:00 and 11:00, as discussed at Table 4. In 2030, the forecasted commercial EV charging peak is 39 MW at the hour ending at 10:00, or about 0.5% of the 2018 C&I of the average winter peak of 6,142 MW at that time.

This forecast is for light vehicles (cars and pickup) charging at publicly available charging stations at commercial locations. It does not include medium and large commercial trucks (buses, delivery vans, long haul trucks etc.) and does not forecast peak hour contributions from these vehicles.

Our C&I solution set recommendation is to begin defining how managed charging will operate during winter peak system peak coincidence. Beginning this process now will accomplish three objectives:

- Profile the market to help refine estimates of system interaction. This would include tracking development of load impacts from medium and large commercial trucks
- Identify technology solutions for which pilot projects can be developed to test different approaches to managing EV charging.
- Define economic benefits that help drive commercial adoption, thereby accelerating revenue growth

Figure 92 provides our analysis of EV load forecast data provided by Duke, showing approximately 100 MW of demand at hour 9 by 2030.

Figure 94. Comparison of C&I and Commercial EV Charging Winter Peak Demand Profiles

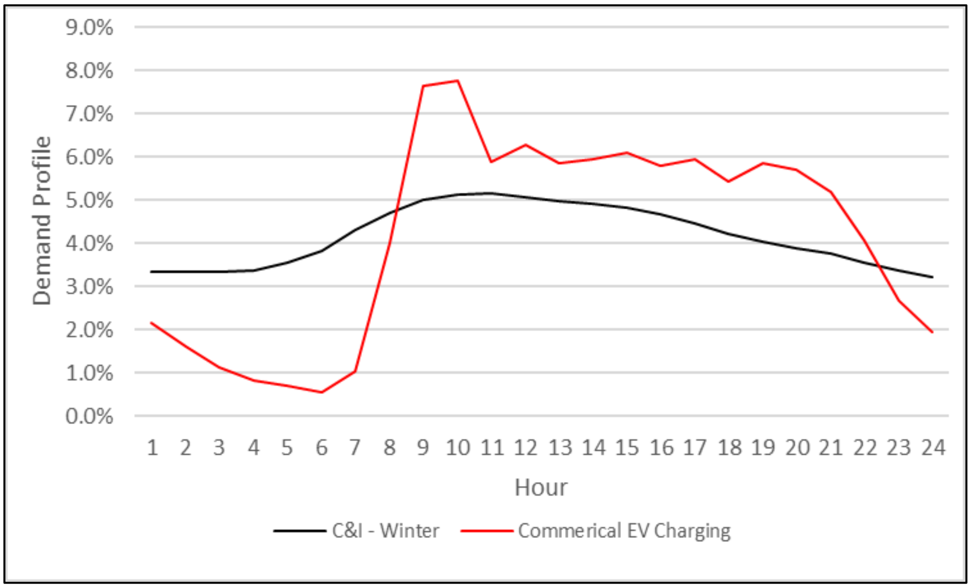
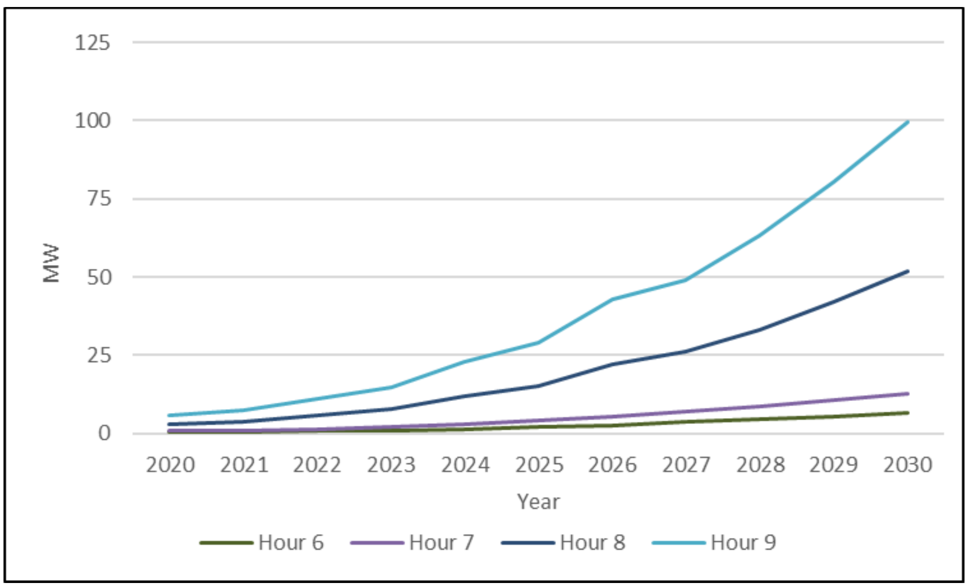


Figure 95. Public EV Charging Load Forecast by Morning Hour



Microgrids

Microgrids offer a potential solution for grid resiliency and reliability initiatives, including management of both winter and summer peak events. For example, Appendix 1, Public Segment DSM Value, provides a discussion on the value of DSM applications in the public sector, including an example of the value microgrid applications in areas where city, county, state, and federal buildings are clustered.

7. Appendices

Appendix 1, Public Segment DSM Value

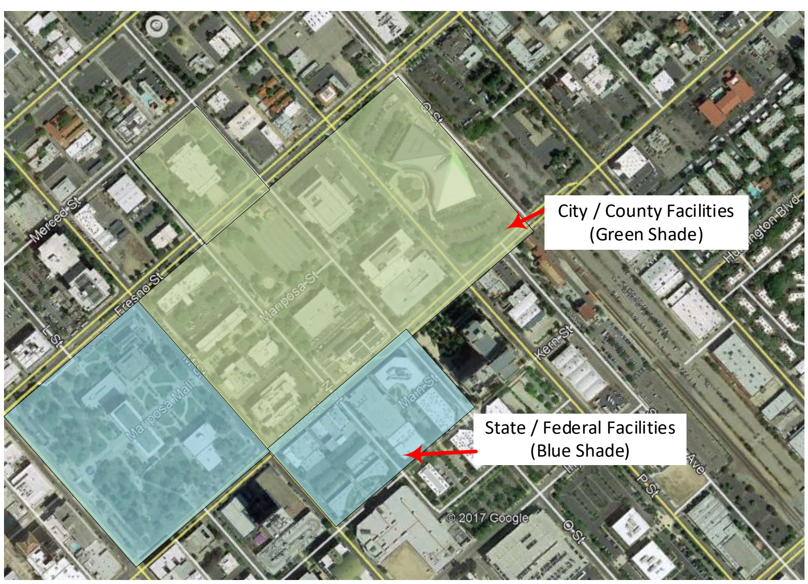
Consider that the public sector has various characteristics that support active load management and has provided market signals that align with an ADR solution:

- The public sector is larges and includes a significant number of facilities operated by several hundred entities across NC and SC, including:
  - Federal
  - State
  - County
  - City
  - Districts (e.g., school and water districts, etc.)
- Most customers at the state, county, and city level are in financial distress and reducing energy costs is a viable and ongoing focus. These entities likely have significant deferred maintenance backlogs where program interventions could help manage fuel and demand charges while supporting facility renewal projects, defined and funded each year through their annual budgets.
- This segment is easy to identify and categorize by NAICS since some facilities (e.g., school, jail, courthouse) rarely change use and once categorized the segment stays the same.
- A core focus of every city or county is to plan development (both new and economic redevelopment) and ensure code compliance. These functions provide excellent platforms to reach broader residential and commercial customers, especially large developers through partnerships that can drive addition participation in Dukes suite of EE and DSM offering.
- In addition to tradition planning activities, a growing number have, or are developing, sustainability initiatives such as the following that would make them amenable to EE/DSM participation:
  - SustainableNC is a partnership initiative to encourage public and private collaboration as NC strives to become a national leader in energy innovation and low carbon economy.
  - Three Zeros Environmental Initiative is UNC-Chapel Hill's principal sustainability program supported through the UNC Office of Sustainability and represents an integrated approach to reducing its environmental footprint through three sustainability goals: net zero water, zero waste to landfills and net zero greenhouse gases.
  - The Raleigh Office of Sustainability works to create an organizational environment where each City departmental operation, investment, and initiative incorporates the Council's commitment to building a sustainable city.
  - City of Durham Sustainability Report communicates the City of Durham's sustainability story to date and informs a strategic path forward with a timeline of major environmental milestones, key indicators, and accomplishments across City departments.
- Public entities have predictable and consistent load profiles that align well with 6:00 a.m. to 9:00 a.m. winter curtailment (and also summer peak events that occur late in the day).
- They are stable customers that are generally safe from economic disruption or changes in their portfolio of facilities.
- There are 100's of public entities in NC and SC that all manage reasonably sized portfolios of buildings and they likely have a single, or a few, point(s) of contact in charge of energy. This can be leveraged to implement efficient outreach and marketing efforts during development. This can also be

leveraged to efficiently manage communication during events, especially long duration events spanning multiple consecutive days.

- Unlike many commercial customers where ownership and decision can be remote, State, County, and City entities reside in Duke's NC and SC territories and have a vested interest in success.
- In general, they have less risk from curtailment than other segments, such as liability concerns related to health care or spoilage issues related to the grocery or warehouse markets.
- Public sector entities control fleets of vehicles, ranging from pools of cars and light trucks to school and transit buses that will electrify over the coming years. Establishing a foundation of load management early in this transition will likely result in a more effective grid response and potentially accelerate revenue growth related to EV adoption. Duke may also leverage relationships with public entities to expand innovations with EV charging designs with EV manufacturers, such as the Proterra, Asheville Redefines Transit (ART) project or the transit systems in North Carolina's Research Triangle grant project.
- Many Public sector facilities often lack sophisticated energy information (EIS) and energy management control systems (EMCS). Targeting this sector presents an opportunity to implement technologies that compliment Duke's AMI and data analytics rollout in a market that is likely using less energy management technology than other commercial segments. EIS and EMCS technologies are the technologies that enable effective load management and provide the additional benefit of supporting more aggressive fuel reduction (e.g., Energy Efficiency).
- Many public sector facilities are clustered in close proximity within major population centers and likely constitute a viable market for advanced technology solutions such as microgrids, either islanded or virtual designs that tie buildings together in a network with a single reporting/control interface. This characteristic makes interconnection across multiple facilities manageable, especially as AMI deployment advances. This characteristic also presents opportunities for district level thermal storage and networked chemical storage. For example, Figure 93 shows a microgrid concept Tierra developed for the City of Fresno, CA, that includes 23 separately metered facilities within a 66-acre area that represented 1.8 MW of total peak load. This design included both hard interconnects and network interconnects where distributed batteries were proposed for peak management through a common reporting and control hub.

Figure 96. Fresno Public Facility Microgrid Footprint



Appendix 2, Water Treatment Segment DSM Value

As discussed at Table 16, both PS and DRA have lost capacity in the water treatment segment from changes in EPA rules that preclude the use of backup generators for DSM purposes. We believe that backup generators are the only source of DSM that Duke pursued in that market segments, however other opportunities exist for the application ADR that are attractive because of the size and diversity of available loads at most plants, and the number of water plants in operation in NC and SC.

The following discussion provides excerpts from a report[57] coordinated by the Demand Response Research Center and funded by the Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy and Office of Electricity Delivery and Energy Reliability, under Contract with the California Energy Commission (CEC), Public Interest Energy Research (PIER) Program. During our work we identified 210 water treatment facilities serving 9,609,446 persons, or approximately 61% of the combined NC and SC population of 15,636,798, many of which are being served by Duke.

Overview

This report summarizes Lawrence Berkeley National Laboratory's Demand Response Research Center (DRRC) work involving California wastewater treatment facilities from 2008 through 2014. Through sector specific research, the DRRC's Industrial Demand Response team assessed the potential opportunities and barriers to implementing automated demand response (ADR) capabilities in these facilities.

DR refers to a set of strategies and systems used by electricity consumers to temporarily modify their electrical load in reaction to electrical grid or market conditions. Three case studies carried out as part of this work suggest that wastewater treatment plants are prime candidates for ADR due to their large energy consumption during utility peak periods, process storage capacity, high incidence of onsite generation equipment, and control capabilities.

Equipment Controls

The following describes specific control opportunities for four types of equipment in the wastewater treatment process:

Aerators:

Implementing automatic dissolved oxygen control for an aeration system can reduce facility energy use by as much as 25%. The control system can automatically adjust blower output at preset time intervals based on a comparison between an average of dissolved oxygen readings in the aeration basins and a recommended dissolved oxygen concentration.

Disinfection Equipment:

Irradiating the waste stream with ultraviolet (UV) light is becoming a common method of disinfection, because unlike traditional processes such as chlorination and ozonation, using UV light does not involve the addition of chemicals. However, UV disinfection uses more electrical power than chemical-based methods. Implementing UV light control strategies can help minimize the impact of this disinfection method on energy costs. For example, control data from the SCADA system can enable facilities to respond to changes in the waste stream, such as increased levels of total suspended solids, turbidity, and biological oxygen demand. Using new on-line sensing technologies can also reduce UV light related power costs. For example, turbidity sensors and UV absorbance sensors can be used in a SCADA system to

[57] Opportunities for Automated Demand Response in California Wastewater Treatment Facilities Arian Aghajanzadeh, Craig Wray and Aimee McKane Environmental Technologies Area August 2015

automatically control power applied to UV lights and to optimize disinfection while eliminating unnecessary power consumption, as well as extending the life of expensive UV lamps.

Load Shed Strategies

There are several opportunities to consider for load shedding in a wastewater treatment facility during demand response events. These include turning non-essential equipment off and transitioning essential equipment to onsite power generators. In addition, facilities can use VFDs to operate motor----driven process equipment (i.e., aerator blowers and pumps) at lower speeds, which reduces demand and better enables process operations to maintain effluent quality within regulatory limits. Lighting systems, as well as heating, ventilating, and air conditioning (HVAC) systems also can be retrofitted to save energy and reduce overall energy demand and operating expenses. Some of the opportunities are more appropriate than others, depending on the equipment type. Further information about specific equipment follows.

Aerator Blowers: In many cases, treatment facilities with diffused aeration systems use 50 to 90% of total electric power demand to run aerator blower motors (Thompson, et al. 2008). Using VFDs to control blower speed and reduce this large demand when possible should be considered. Simply shutting down blowers during demand response events also could be an effective way to significantly reduce the plant's energy demand.

Pumps:

Pumps are used in the majority of wastewater treatment processes, including influent pumps, grit pumps, and lift pumps. Given that the energy required for influent wastewater pumping alone can range from 15 to 70% of the total electrical energy, there is a significant opportunity to shed loads associated with pumping. (Thompson, et al. 2008) Pumps are often oversized for the average wastewater flow and thus operate inefficiently. Wastewater treatment facilities can frequently address inefficiencies due to pump oversizing by using VFDs or applying operational strategies that involve staging multiple pumps, which allows for more efficient utilization of pumping capacity.

Load Shift Strategies

Implementing load shift strategies in wastewater treatment facilities allows the main energy-intensive treatment process to be rescheduled to off-peak hours. Electrical load management is a frequently used method for reducing energy use in these facilities and can result in 10 to 15% energy savings. The following discusses over-oxygenation, untreated wastewater storage, process rescheduling, and anaerobic digestion opportunities to shift load.

Over-Oxygenation:

Dissolved oxygen (DO) is necessary for microorganisms to breakdown organic material present in water. A major opportunity for shifting wastewater treatment loads from peak demand hours to off-peak hours is over-oxygenating stored wastewater prior to demand response event. Doing so allows aerators to be turned off during the peak period.

Storing Wastewater:

If site conditions allow, wastewater treatment facilities can utilize excess storage capacity to store untreated or partially treated wastewater during demand response events and then process it later during off-peak hours. However, building storage basins can be expensive, so equalization basins can be used instead. Equalization basin drains open and close as needed to maintain a constant level in the influent wet well, which creates a near constant flow through the treatment process. Unused tanks can be converted into equalization basins during facility upgrades and expansions. Treated wastewater can be stored as well. In one of the case studies, pumping treated effluent to the ocean was simply shifted to off-peak hours

Process Rescheduling:

Facility processes such as backwash pumps, biosolids thickening, dewatering and anaerobic digestion can be rescheduled for operation during off-peak periods, providing peak demand reductions in wastewater treatment facilities.

Anaerobic Digestion:

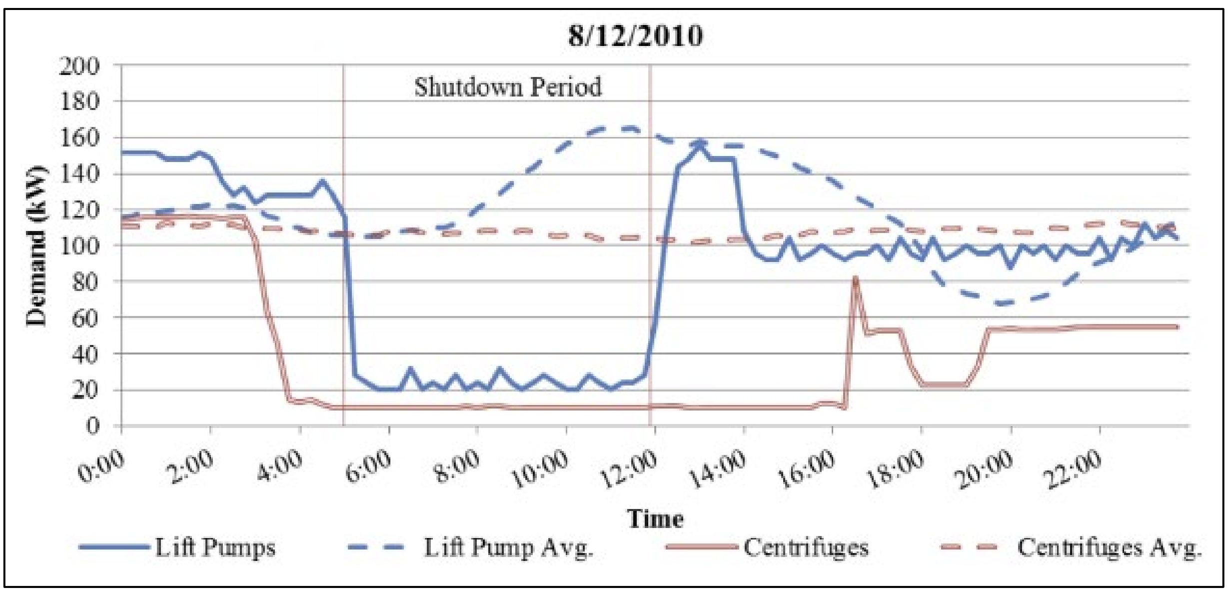
Using the biogas from anaerobic digestion to produce electricity can be an important demand response resource for the wastewater facilities.

Case Study

The average baseline demand at the Southeast facility was approximately 4 MW. During the rainy season (October----March), the facility treated 40% more wastewater than during the dry season but demand only increased by 4%. More specifically, analyses of the collected data found a strong correlation between daily influent flow and total lift pump demand (R2=0.55) but no correlation between influent flow and centrifuge demand. The data also indicated that the demand from the lift pumps and centrifuges during normal utility peak hours (12 p.m. to 6 p.m.) was not substantially different than the demand during the rest of the day.

Based on the sub metered data, on average, 154 kW and 86 kW of load shift are available from the lift pumps and centrifuges, respectively, for a total shift of 240 kW (approximately 6% of average plant demand). Similar shifts were observed during partial-day plant shutdowns. A reduction in demand from lift pumps and centrifuges during one such shutdown is shown in Figure 94.

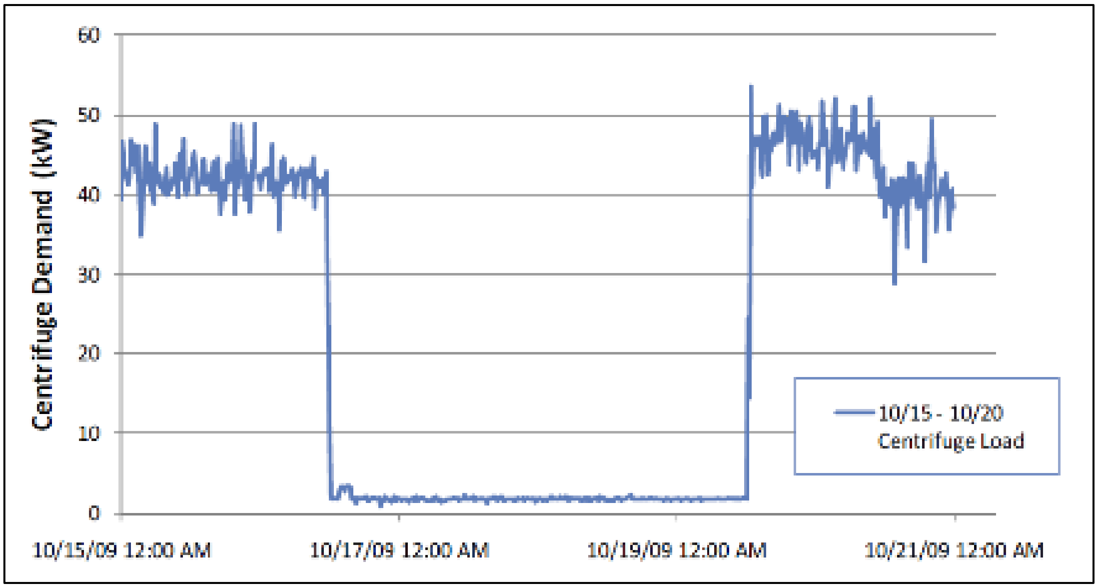
Figure 97. Shift Profile, Wastewater Treatment Plant Case Study #1



In this case study, the plant's influent flow followed a diurnal pattern of a morning and evening peaks, with a sharp dip at night. There was a small positive correlation between outdoor air temperature and influent flow. Further, this study observed that this facility maintains a stable level of dissolved oxygen even as influent varies. This was accomplished through the use of a modulating value that adjusts the amount of air reaching the basin. There was a slight correlation between the outdoor air temperature and dissolved oxygen levels at this facility.

Demand response tests on the effluent pumps resulted in a 300 kW load reduction. Tests on the centrifuges resulted in a 40 kW load reduction, as shown in Figure 95. These reductions from the centrifuges and effluent pumps were enabled by the large potential for onsite storage of sludge and effluent, respectively. Although tests on the facility's blowers resulted in peak period load reductions of 78 kW, as discussed in Chapter 4 of the study, sharp, short-lived increases in effluent turbidity occurred within 24 hours of the test.

Figure 98. Shift Profile, Wastewater Treatment Plant Case Study #2



Appendix 3, DSM Program Structures and Types

Table 55. DSM Program Structures

OPCO	Curtailable Program	Contract Term	Contract Commitment	One-Time Participation Incentive	Monthly Capacity Credit	Event Reduction Credit	Event Non-Compliance Definition/Penalty	Minimum Annual Events
DEP	DRA	Initial 5-year automatic 2-year renewals	Fixed Reduction	$50/kW	$3.25/kW	$6.00/kW	<90% of Contract/ Loss of 4 monthly credits	3 summer
DEP	LLC	Initial 5-year automatic 2-year renewals	Firm Demand	-	NC - $5.40/kW SC - $4.60/kW + $1.02/kW adder	-	Event Demand above Firm Demand/ NC - $50/kW; SC - $45/kW	-
DEC	PS-M	Initial 3-year, automatic 1-year renewals	Firm Demand	-	$3.50/kW	$0.10/kWh	Event Demand above Firm Demand/ $2.00/kWh	-
DEC	PS-G	Initial 3-year, automatic 1-year renewals	Fixed Reduction	-	$3.50/kW	$0.10/kWh	Event Demand above Firm Demand/ $2.00/kWh	12 monthly tests
DEC	PS-V	Initial 1-year, automatic 1-year renewals	Firm Demand	-	-	Energy credit based upon market prices	Event load reduction less than 50% of nominated load reduction/ Loss of event credit	-
DEC	IS	CLOSED	Firm Demand	-	$3.50/kW	-	Event Demand above Firm Demand/ $10.00/kW	-
DEC	SG	CLOSED	Fixed Reduction	-	$2.75/kW + $10 compliance adder	Energy credit based upon market fuel costs	-	12 monthly tests

Table 56. DSM Program Types

OPCO	DSM Curtailable Programs	Legacy Rate Base Curtailable Programs	Legacy Dynamic Pricing Rate Schedules	Legacy Rate Base Non-Firm Rates & Riders
DEP	Demand Response Automation (*Rider DRA*)	Large Load Curtailable (*Rider LLC*)	Large General Service Real Time Pricing (*LGS-RTP*)	Incremental Power Service (*Rider IPS*)
DEP		Large General Service - Curtailable Time-of-Use (*LGS-CUR-TOU*)*		Dispatched Power (*Rider 68*)
DEP				Supplementary and Non-Firm Standby Service (*Rider NFS*)
DEP				Supplementary and Interruptible Standby Service (*Rider 57*)
DEC	PowerShare Mandatory Option (*Rider PS*)	Interruptible Power Service (*Rider IS*)**	Hourly Pricing for Incremental Load (*HP*)	*n/a*
DEC	PowerShare Generator Option (*Rider PS*)	Standby Generator Control (*Rider SG*)**		
DEC	PowerShare Voluntary Option (*Rider PS*)			

DUKE ENERGY

DUKE ENERGY

Winter Peak Demand Reduction Potential Assessment

December 2020

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1 WINTER PEAK DSM POTENTIAL MODELING OVERVIEW

Duke Energy North Carolina and South Carolina engaged Dunsky Energy Consulting, as part of the Tierra Inc team to model the winter peak demand reduction potential in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems.

The objectives of this modelling exercise were to

1) Capture the potential for new programs and measures to reduce the winter peak demand in each of DEP and DEC, via Demand Side Management (DSM) programs target to residential and commercial customers
2) Quantify the degree to which this potential is incremental to the current Duke DSM program impacts, and compare the findings to the Market Potential Study, recently conducted by Nexant[1].
3) Provide insights that can help Duke prioritize winter peak DSM approaches in the short term, as well as identify the potential for longer term strategies.

Following on Tierra's work to identify and characterize new rate structures and mechanical solutions, the winter peak DSM potential assessed the ability of behavioral measures, equipment controls and industrial and commercial curtailment to reduce Duke's overall system peak in each system.

The report includes an introduction to the modelling methodology, followed by a step-by step description of the model findings. The overall potential assessment is then provided in section 3 of this report, followed by a concluding section containing key take-aways. Finally, a set of detailed results and input assumptions is appended.

1.1 DSM POTENTIAL ASSESSMENT APPROACH

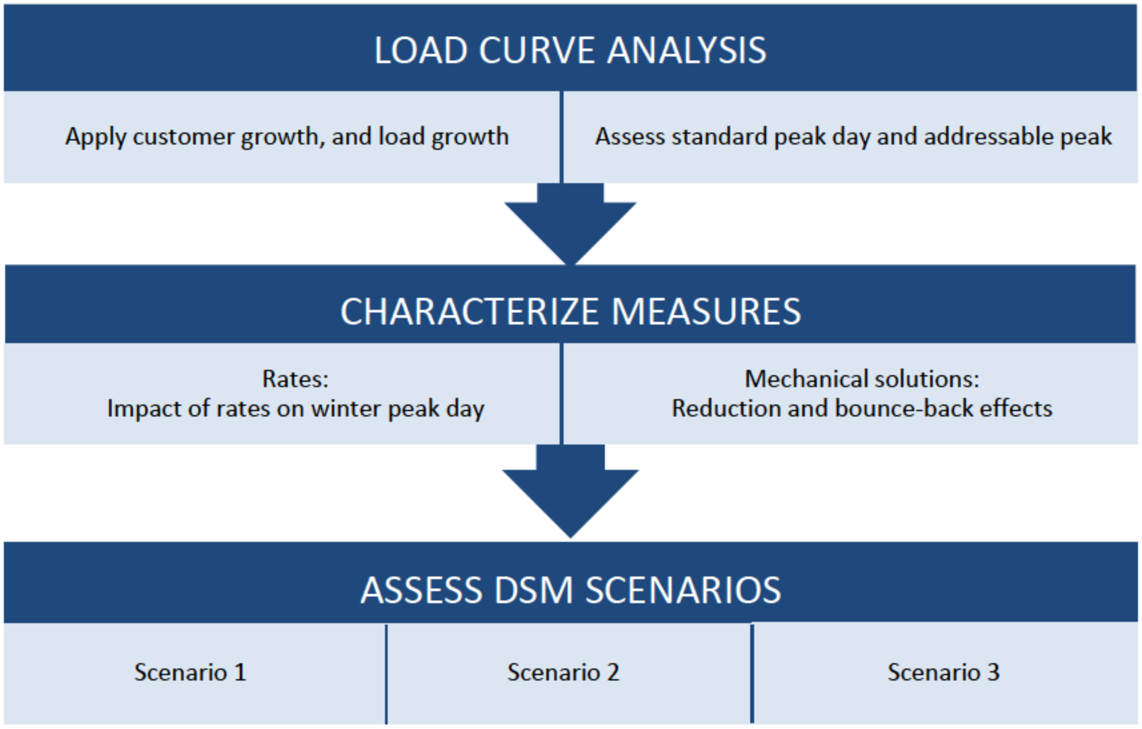
The DSM potential is assessed against Duke's hourly system load curves and winter peak demands. Figure 1 below presents an overview of the steps applied to assess the DSM potential in this study.

Key to this assessment is the treatment and consideration Duke's DEC and DEP winter system peak-day hourly load curve. As part of this process, standard peak day 24-hour load curves are identified and adjusted to account for projected load growth over the study period. This allows the model to assess each measure's net reduction in the annual peak, considering possible shifts in the timing and duration of the annual winter peak in each system.

In some cases, this may lead to results that are contrary to initial expectations, especially when DSM programs such as dynamic rates or equipment direct load control (DLC) measures are looked at only from the perspective of how they may impact individual customer peak loads at the originally identified peak hour.

[1] Nexant, *Duke Energy North Carolina EE and DSM Market Potential Study,* and *Duke Energy South Carolina EE and DSM Market Potential Study*, May 2020

Figure 1 - DSM Potential Assessment Approach



The achievable potential is assessed under three scenarios corresponding to varied DSM approaches or strategies (Figure 2). These scenarios were developed with the goal of assessing the impacts of different rate structures and a selected set of mechanical solutions on the load curve of both DEC and DEP. More details on the scenarios can found in the section 3.3 of this report.

Figure 2. Demand Response Program Scenario Descriptions

LOW	Applies a limited number of rate structures with conservative adoption or incentive levels in conjunction with a defined set of mechanical solutions.
MID	Introduces an additional rate structure into the residential market and increases C&I adoption or incentive levels. Mechanical solutions are adapted to the new rate structures.
MAX	Applies a variety of residential rate structures and more aggressive C&I adoption and incentive levels to estimate maximum achievable potential. Mechanical solutions are adapted to the new rate structures.

1.2 SEGMENTATION

Market segmentation is essential to accurately estimate the DSM potential and is one of the first step of the modelling. Customer information provided was broken down by rate class for both DEC and DEP. As rates patterns and DSM savings vary by customer characteristics, DEC and DEP customers were segmented in three ways:

- **By market sector**: Residential, Commercial and Industrial

- **By rate class**: Within each sector, customers can choose a variety of rate classes, depending on their overall size (assessed by annual peak kW power draw) and rate structure preference. By segmenting customers according to their applicable rate classes, the model can assess the impact of customers moving to new or adjusted rate structures. The key rates classes in both DEP and DEC and presented in Table 1. Both “other” rates encompass all the other rates not specifically mentioned that are available in each system.

Table 1 – Rate Class Segmentation

DEC - Rates	DEP - Rates
SGS	SGS
LGS	MGS
OPTC	LGS
OPTI	RTP
RS	Res
RE	Other
Other	

- **By customer segment:** Within each market sector/rate class segment, Duke’s commercial and industrial customers were further segmented by business type (i.e., offices, schools, retail etc.) using U.S. Energy Information Agency’s (EIA) Commercial Buildings Energy Consumption Survey (CBECS - 2012) and Residential Energy Consumption Survey (RECS - 2015).

2 DSM POTENTIAL ASSESSMENT

2.1 STEP 1 - LOAD CURVE ANALYSIS

The peak load analysis is the first step in the DSM potential analysis, through which key constraints are defined to identify the solutions that will be deployed, and the scenarios modelled to reduce winter peak demands.

First, the winter season standard peak day load curve is defined, and the impacts of load growth projections are applied. The standard peak day load curve for the electric system is defined by taking an average of the load shape from each of the top ten winter peak days in the forecasted hourly load data provided[2] (Figure 3 for DEC and Figure 4 for DEP).

Figure 3 - DEC Standard Peak Day (incl. wholesale) Based on Historical Data – 2020

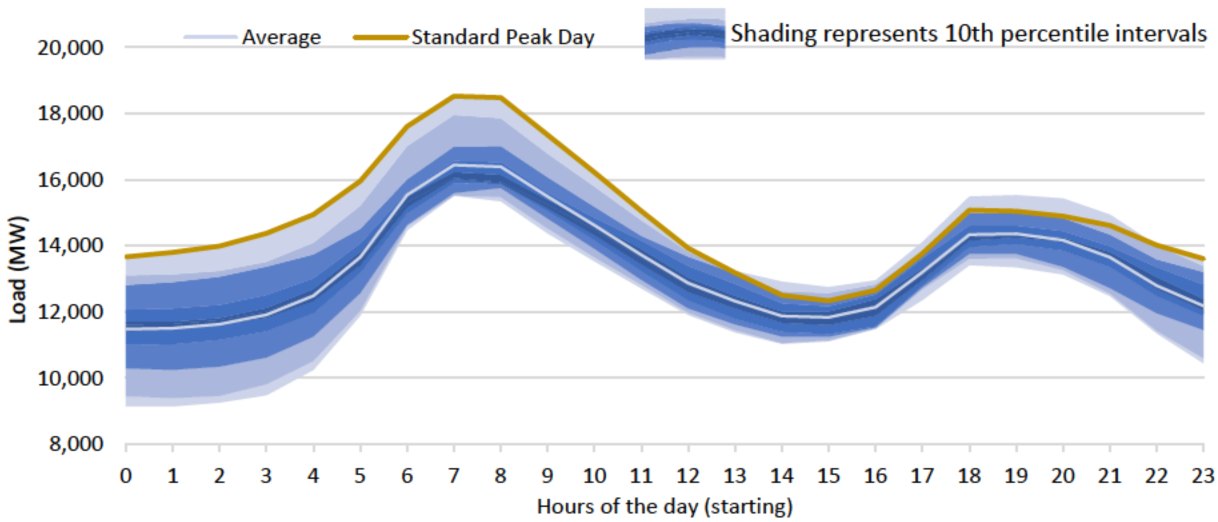
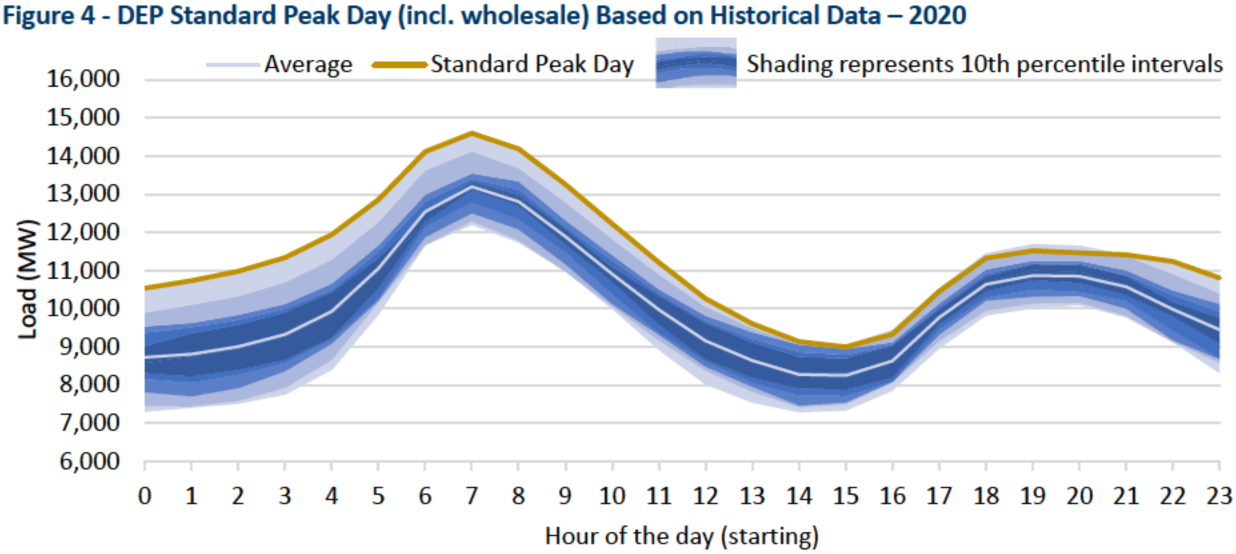


Figure 4 - DEP Standard Peak Day (incl. wholesale) Based on Historical Data – 2020



[2] Provided forecast included years between 2020 and 2045.

This analysis shows that Duke's systems, in winter, have a steep morning peak, which is driven predominantly by residential and commercial space heating. The duration and steepness of the peak curve indicate that measures with bounce-back or pre-charge effects are not likely to pose a real problem in winter by creating new peaks when shifting load from one hour to another.

An hourly load forecast was provided, for each year from 2021 to 2041, thus the winter peak load curve assessment was repeated for each year to determine the annual winter peak in each of the year of the study period (2021-2041), resulting in the peak day characteristics listed in Table 2 below.

Table 2 – Standard Peak Day Key Metrics

Year	Peak Demand (MW) excl. wholesale	
	DEC	DEP
2021	16,533	10,551
2026	16,611	10,661
2031	17,242	11,020
2036	18,191	11,593
2041	19,315	12,332

Once defined, the standard peak day utility load curve is then used to characterize the DSM solution set measures, by defining the peak load reduction possible at each hour of the day. These are then used to assess the measure-specific peak demand reduction potentials at the technical and economic potential levels.

2.2 STEP 2 - SOLUTION SET CHARACTERIZATION

Based on the load analysis and detailed review of Duke's current program and rates[3], a solution set was developed to reduce the winter peak demand in both DEP and DEC. The mechanical solutions and rate structures considered are described below.

2.2.1 MECHANICAL SOLUTIONS

As outlined in Tierra's Winter Peak Analysis and Solution Set report, a solution set was identified to specifically address the DEC and DEP winter peak. Once selected, measures were characterized individually. Measure characterization is the process of determining the hourly load curve impacts (kW reductions in each hour), as well as the measure costs, applicable markets and EULs. The measure characterizations leverage a range of secondary sources, including energy modelling profiles and empirical data from relevant jurisdictions to determine the resulting load curve impacts.

Based on the Winter Peak Analysis and Solution Set report analysis, a total of eight technologies/programs were chosen to be integrated into the modelling.

[3] More details are provided in Tierra's Winter Peak Analysis and Solution Set report.

- **Residential**
  - Bring Your Own Thermostat (BYOT)
  - Rate Enabled Thermostats (RET)
  - Rate Enabled Residential Hot Water Heating Controls (RE-HWH)
  - Winter Heat Pump Tune-up
  - Battery Energy Storage[4]
- **Small and Medium C&I**
  - Bring Your Own Thermostat (BYOT)
  - Rate Enabled Thermostats (RET)
  - Winter Heat Pump Tune-up
- **Large C&I**
  - Automated Demand Response (ADR) for larger C&I flat rate customers selecting advanced rates

More details on the key measure inputs are provided in the Winter Peak Analysis and Solution Set report.

2.2.2 RESIDENTIAL RATES

Close attention was paid to the rates structure as they not within the scope covered by Nexant's 2020 MPS study, and thus they provided an opportunity to determine if and where further potential for winter peak reductions may lie. Rates are used to encourage customers to modify their behavior and change consumption patterns. Four specific rates structures were designed for the study, applying the three common residential dynamic rate structures: Time-Of-Use Rate (TOU), Critical Peak Pricing (CPP) and Peak Time Rebate (PTR). Based on the load curve analysis, the peak hour charges were applied from 5:00 am to 9:59 am on weekdays only.

- **TOU Rate**
- **TOU Rate with CPP**
- **Bill Certainty with PTR**
- **Flat Volumetric with CPP**

Further details on the Residential DSM rates are provided in the appendix.
5

2.2.3 COMMERCIAL & INDUSTRIAL RATES

Commercial rates were derived for customer segments small, medium, and large annual consumption profiles. Both CN&I rates apply PTR rates to attract customers by providing a benefit for demonstrated

[4] The forecast of residential Battery Energy Storage represents a conservative view based on uncertainties about market adoption for this technology and is discussed in more detail in the Winter Peak Plan report completed as part of this same research effort.

[5] The reports produced by the Winter Peak Study, including the Winter Peak Demand Reduction Potential Assessment report, use the term Commercial and Industrial to discuss rates used by the non-residential market sectors and is intended to help define the significant difference in load shapes between commercial and industrial customers and also define DSM opportunities targeting each market segment, Commercial and Industrial rates and customers may be referred to as "Non-residential" or "General Service" rates in other Duke publication and communications.

peak event demand reductions. By using a rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times

- **Small C&I Customers – Bill Certainty with PTR**
- **Medium and Large - C&I Customers - PTR**

For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count. Further details on the C&I DSM rates are provided in the appendix.

2.3 STEP 3 - SCENARIOS

As a final analysis step, three defined adoption scenarios are applied, and the winter peak impacts are assessed. Three scenarios were developed to be viable in both DEC and DEP systems, with key program inputs defined for each. This section summarizes the selected scenarios and main program inputs.

2.3.1 LOW SCENARIO

The low scenario includes a solution set that includes the most straight-forward combination of rate options. A new residential TOU rate structure would be offered along with a TOU+CPP option. On the C&I side, a PTR rate would be deployed with a conservative adoption rate for SGS customers and a low PTR incentive for medium and large C&I.

Table 3 – Overview of the Low Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Low adoption (10%) • Medium and Large C&I - PTR Low incentive (30$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I- BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.2 MID SCENARIO

The Mid scenario aims to expand on the Low scenario by including a new residential Bill Certainty rate option and increase adoption and PTR incentives in the C&I sector.

Table 4 – Overview of the Mid Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Mid adoption (15%)

	• Bill Certainty + PTR Rates	• Medium and Large C&I - PTR Mid incentive (60$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.3 MAX SCENARIO

The Max scenario aims to maximize demand response potential by adding a new CPP option, maximizing adoption in small C&I, and increasing medium and large C&I PTR incentives to approach the limits that still render the programs cost effective (i.e., the incentive levels that yield UCT results of 1.2 or higher).

Table 5 – Overview of the Max Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates • Bill Certainty + PTR Rates • Flat Volumetric + CPP Rates	• Small C&I - Bill Certainty + PTR High adoption (20%) • Medium and Large C&I - PTR High incentive (90$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.4 KEY VARIABLES FOR DSM POTENTIAL ASSESMENT

The variables below are key to the DSM assessment as they feed the achievable potential and costs calculation. These assumptions were developed based on Duke's inputs, jurisdictional scans and professional judgment.

RESIDENTIAL PARTICIPATION RATES

Table 6 below summarizes adoption levels for each DSM rate per under each scenario treatment.

Table 6 – Adoption for Residential Rates*

	Low Scenario			Mid Scenario			Max Scenario		
Target Rate	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**
TOU	2%	10%	5%	2%	10%	5%	4%	20%	11%
TOU + CPP	10%	15%	12%	10%	15%	12%	6%	9%	7%
Bill Certainty + PTR	-	-	-	8%	20%	13%	10%	25%	16%
Flat Volumetric + CPP	-	-	-	-	-	-	4%	11%	7%
Total residential Market	***12%***	***25%***	***18%***	***21%***	***45%***	***31%***	***25%***	***65%***	***42%***

*Due to rounding, numbers may not add up

Adoption levels were first determined for the DEC all-electric residential rate class (RE). It is expected that this rate class would benefit the most from the selected rates structures (higher electric bills and peak demand) and therefore, the rate with the highest adoption levels. Adoption levels for all-electric residential rate are derived from Brattle's Time-Varying Price Enrollment Rates Study[6], a study that bundles results from six market research studies and fourteen full-scale deployments. Based on this study findings, for an opt-in residential dynamic rate, TOU rates can reach on average 28% of the customers, CPP rates can achieve an average of 17% and PTR rates average 21%.

For the Low scenario, it is therefore assumed that a total of 25% of RE customers would enroll in a TOU rate structure after full deployment of the rates. Of those customers willing to join a TOU rate, it is estimated that 15% would prefer a TOU+CPP version of the rate. For the Mid scenario, the adoption for PTR was assumed to be 20% of RE customers. It is important to note that to keep conservative estimates, the averages for all residential customers from the Brattle study were applied as our highest adoption estimates for the RE rate class only.

Finally, for the Max scenario, the objective was to reach a maximum of customers through large-scale deployment and intensive marketing. It is estimated that a total of 28.5% of customers will be interested in a TOU rates structure, corresponding to the average from the Brattle's Time-Varying Price Enrollment Rates Study. Based on findings from Sacramento Municipal Utility District's Consumer Behavior Study[7], it is assumed that the participation rates between TOU+CPP and a CPP rate would be similar with a slightly preference for a CPP rate structure[8]. This was further corroborated through the preliminary survey results from Duke's Flex Savings Options Pilot. As for PTR, adoption levels as high as 56% were achieved in other jurisdictions. Taking into consideration the multiple rates offered conjointly in this scenario, a maximum adoption of 25% has been selected.

Once RE rate class adoption levels were established, those levels were used to determine the potential adoption for DEC standard residential rate (RS) which mainly includes non-electric heated customers. The adoption levels were assumed to be proportional to the average bill savings. The lower the bill savings, the lower the adoption. Load impact results from the Flex Savings Options Pilot were used to assess the level of achievable savings.

Finally, adoption rates for customers under the DEP residential rates were prorated based on the number of customers all electric versus non-electric heated.

C&I PARTICIPATION RATES

Table 7 below present the incentives and adoption level used for the C&I DSM rate scenarios.

Table 7 – Adoption for C&I Rates

C&I	Low Scenario	Mid Scenario	Max Scenario

[6]Adoption for opt-in dynamic rates from R. Hledik, A. Faruqui and L. Bressan, *Demand Response Market Research: Portland General Electric, 2016 to 2035 – Appendix A: Participation Assumptions*, 2016.

[7] SMUD, *SmartPricing Options Final Evaluation*, 2014. Retrieved at: https://www.smud.org/-/media/Documents/Corporate/About-Us/Energy-Research-and-Development/research-SmartPricing-options-final-evaluation.ashx

[8] The TOU+CPP rate structure had a higher percentage of drop-out customers than the CPP rate structure (7.7% vs 5.7% - Figure 1.2). Our estimates use drop-out percentages rather than acceptance rates because acceptance rates reflect decisions made at the beginning of the pilot, before experiencing the rate.

Bill Certainty + PTR (Small C&I) Adoption	10%	15%	20%
PTR (Medium & Large C&I) Incentives	30$/kW/yr	60$/kW/yr	90$/kW/yr

Small C&I Customers

Adoption levels were also based on Brattle's Time-Varying Price Enrollment Rates, with again a reduction factor to account for the low elasticity of the small C&I sector. Since there is uncertainty in this approach, three scenarios, with various adoption levels were modelled to see the impact of adoption on demand response potential.

Medium & Large C&I Customers

For the medium and large C&I rates, the model determines the expected maximum program participation based on the incentive offered, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves developed by the Lawrence Berkeley National Laboratory[9]. The propensity curve was calibrated to the existing participation level from DRA and PowerShare.

OTHER PROGRAM OUTPUTS

The modelling includes several program inputs. Below are presented a few of these key variables. More detailed are included in Appendix A.2.

Participation and Enrollment Ramp up: Participation and enrollment ramp ups are applied to every modelled solution. The BYOT program is assumed to be deployed in 2021 while all other programs are not assumed to start before 2022 at least. The low scenario assumed a 5-year ramp up for each rate solution while the Mid and Max scenarios assume an 8-year ramp up.

Program Costs: For every DSM program, a one-time fixed cost is applied for program development. For recurring costs, an annual fixed cost is assumed along with a variable cost per customers. Program costs also include sign-up and/or annual incentives.

Program Lifetime: For mechanical solutions, programs are assumed to last for the whole measure life.

[9] Lawrence Berkeley National Laboratory, *2025 California Demand Study Potential Study: Phase 2 - Appendix F*, March 2017. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

3 DSM ACHIEVABLE POTENTIAL RESULTS

The overall achievable winter DSM potential in each year for each scenario is presented below, and in all cases the values are presented are incremental to current DSM program winter peak impacts. These results represent the overall winter peak load reduction potential when all constituent programs are assessed together against the DEP and DEC load curves, accounting for combined interactions among programs and reasonable roll-out schedules.

Measures that cost-effectively deliver sufficient peak load reductions individually are retained and applied in the achievable potential scenario analysis. Consistent with the other savings modules in this study, only cases where the measure yields a Utility Cost Test (UCT) value greater than 1.1 are retained in the economic and achievable potential.

Under the Low scenario, which represents the most conservative scenario, the winter potential is estimated to reach **1,079 MW in 2041** (651 MW in DEC and 428 MW in DEP), which represents 3.4% and 3.5% of DEC and DEP peak, respectively. Under the Mid and Max scenarios, the achievable potential estimates respectively achieve **1,273 MW** (766 MW in DEC and 507 MW in DEP) and **1,378 MW** (834 MW in DEC and 544 MW in DEP) **in 2041**, translating into 4.0% (DEC) and 4.1% (DEP) for the Mid scenario and 4.3% (DEC) and 4.4% (DEP) for the Max scenario of the systems peaks. Based on these results, the scenario analysis indicates that DSM rate structures that have been piloted by Duke (TOU and TOU+CPP) can capture a little over 45% of the expected potential from DSM rates, while the rest of the potential lies in new rates offers (PTR and CPP).

Figure 5 – DEC potential, by scenario

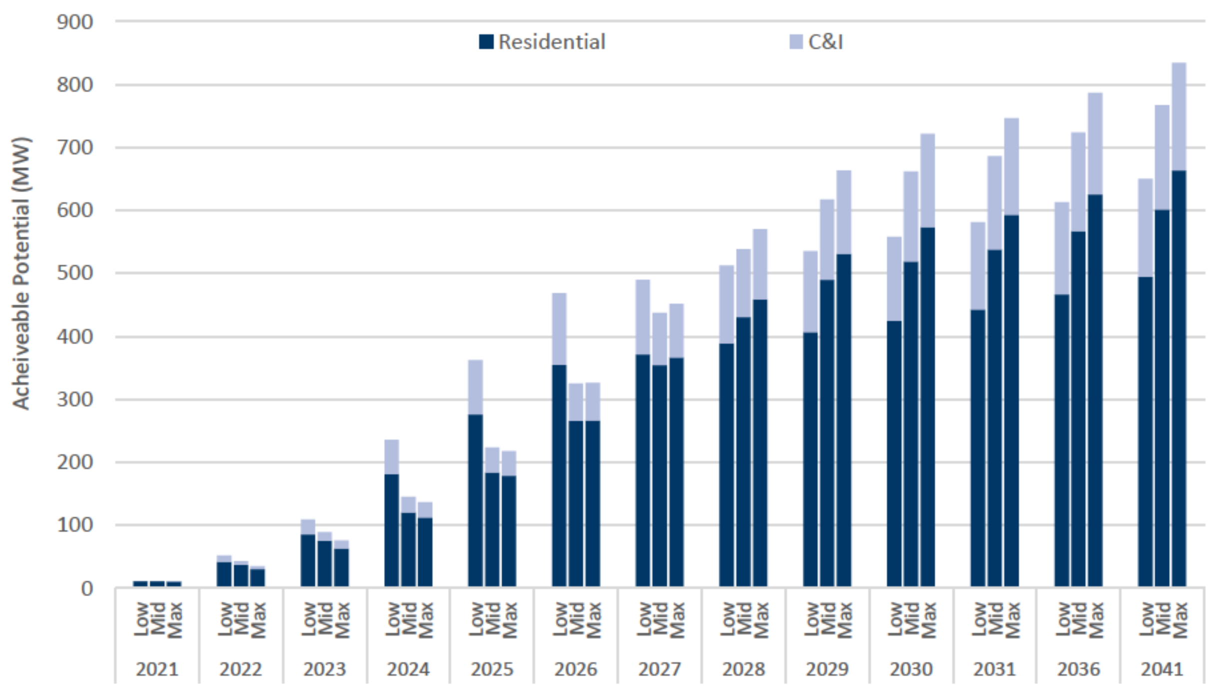


Figure 6 – DEP potential in each study year by scenario

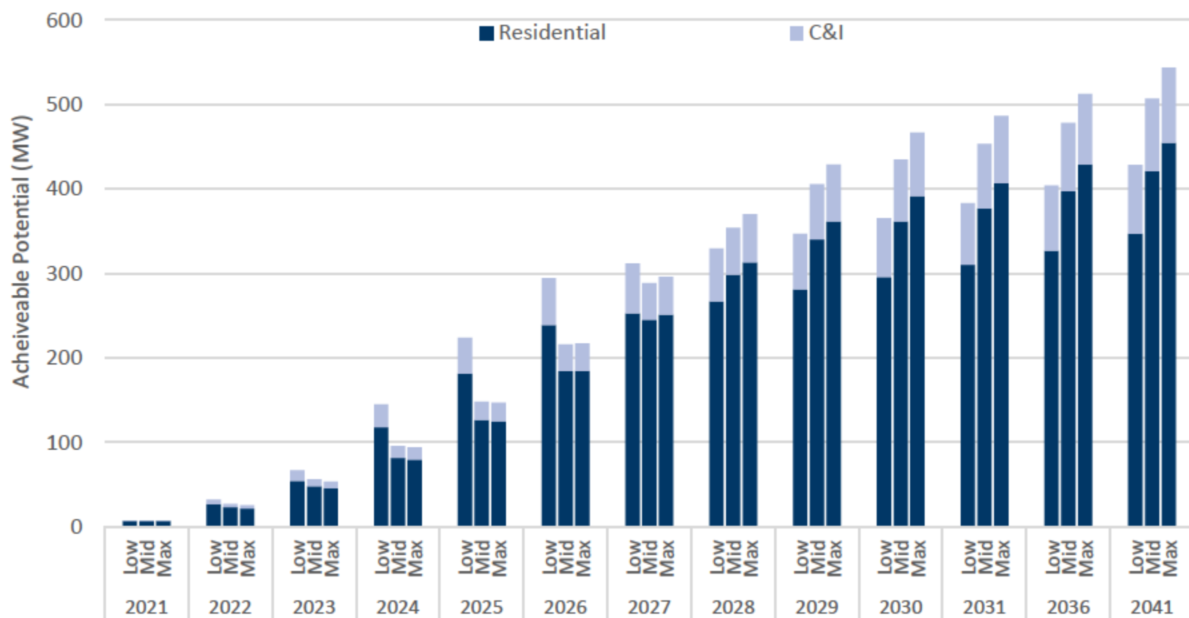
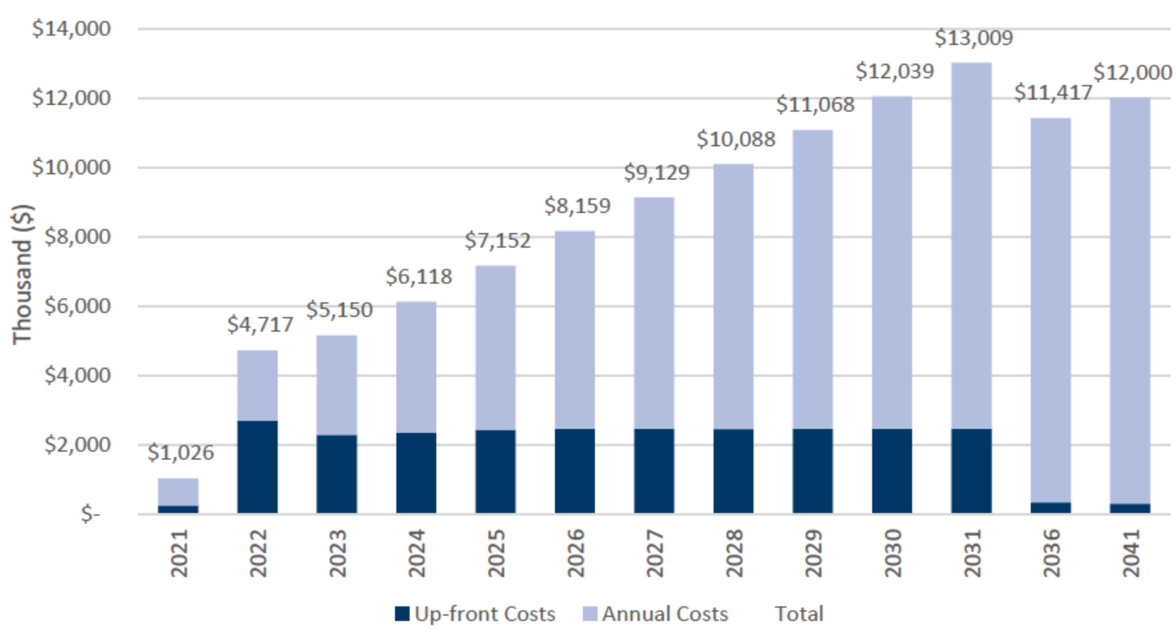


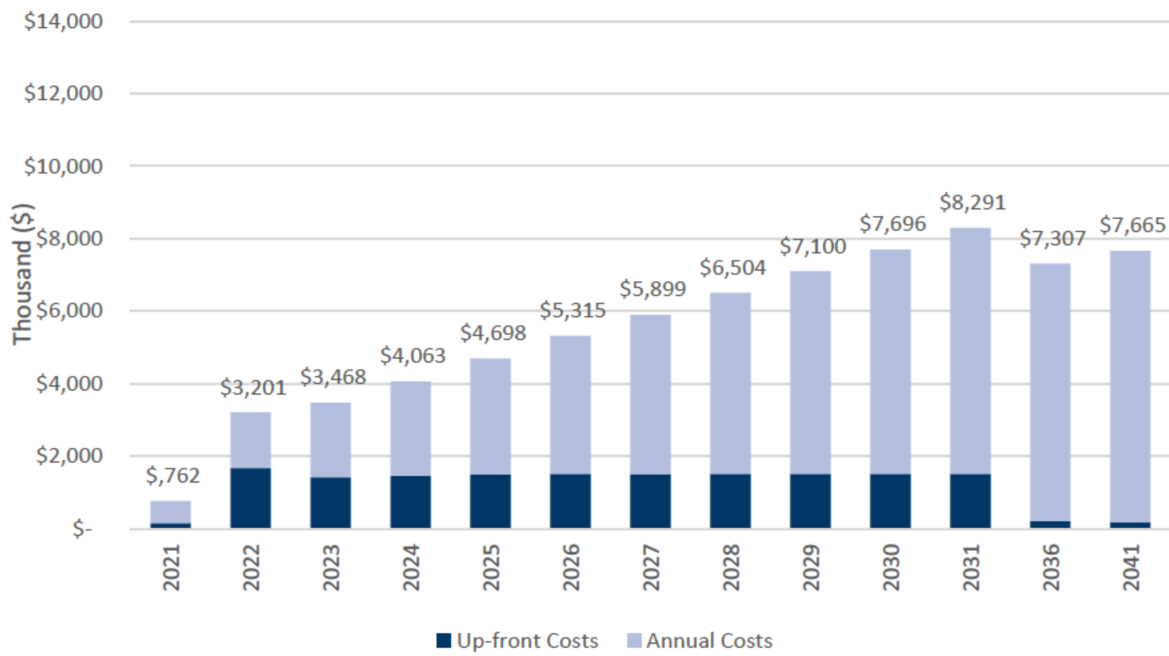
Figure 7 and Figure 8 below provide the program costs for mechanical solutions, broken down by upfront measure costs[10], and program administration costs and customer incentives. The set of mechanical solutions measures are constant throughout all scenarios. The results show higher up-front costs in the initial development years as new programs are developed, new customers are enrolled in the programs and new controls systems are put in place.

Figure 7 – DEC Mechanical Solutions Costs



[10] Upfront measure costs include sign-up (enrollment) incentive costs, as well as controls and equipment installation costs.

Figure 8 – DEP Mechanical Solutions Costs



The Utility Cost Test (UCT) results assume that participants will stay enroll for 10 or 11 years, depending on the expected measure life. Table 8 provides cost-effectiveness results based on a program lifetime basis.

Table 8 – DEC Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	3.2
Residential BYOT	4	4.9
Residential Rate-Enabled HWH	11	1.3
WP/HP Tune-up	10	2.0
Commercial Rate-Enabled T-Stat	10	2.7
Commercial BYOT	4	3.6
Residential BYOB	10	0.5
ADR	10	4.1

Table 9 – DEP Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	2.3
Residential BYOT	4	3.7
Residential Rate-Enabled HWH	11	1.0
WP/HP Tune-up	10	1.2
Commercial Rate-Enabled T-Stat	10	1.6
Commercial BYOT	4	2.2
Residential BYOB	10	0.3
ADR	10	2.8

All modelled measures were cost-effective on a lifetime basis except for residential battery energy storage. This measure is cost-effective at measure level but fails the test at program level due to the costs required for running the program (fixed program costs) because it is assumed that there are a small number of residential battery systems currently installed among Duke's residential customers.

The impacts assessed for each scenario on the standard winter peak day in 2031 are shown in Figure 9 and Figure 10, where all programs are at full deployment. The assessment reveals that the combined impacts of the DSM rates and measures are not sufficient to alter the timing of the winter peak on the standard peak day. Thus, the net potential, is assessed as the achieved load reduction at the identified peak hours. For DEC, the load is nearly flat from 7:00 to 8:59, emphasizing the importance to target not only the peak hour, but the whole peak.[11]

[11] Our definition of peak did not consider wholesale transactions because the EE and DSM programs included in the solution set will not be available to this market

Figure 9 – DEC: Scenario Impact on Peak Day Load Shape (2031)

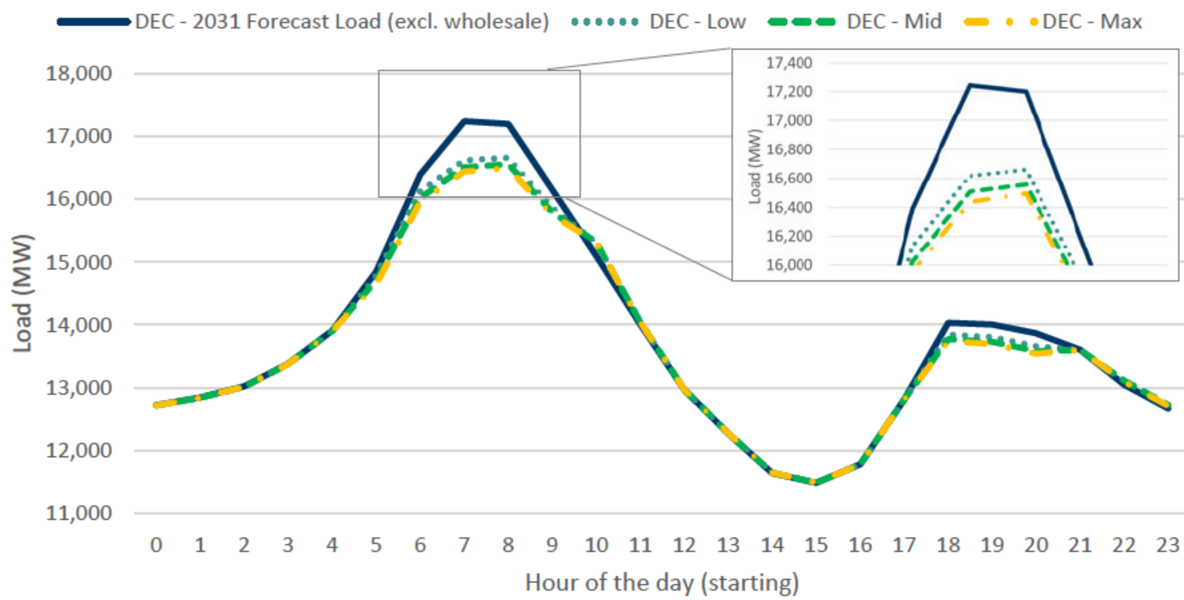
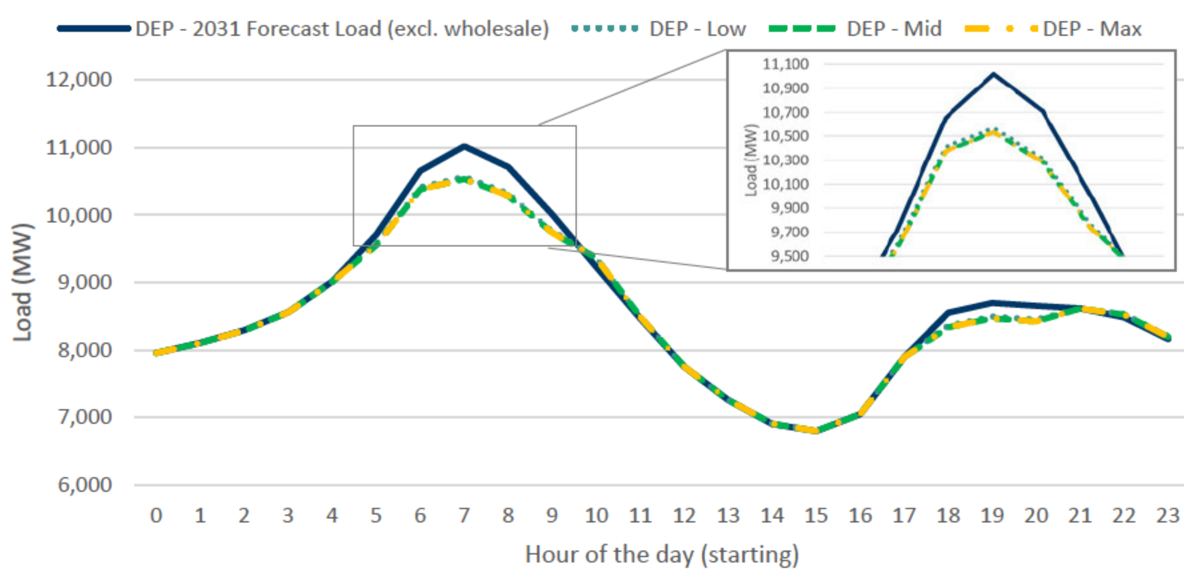


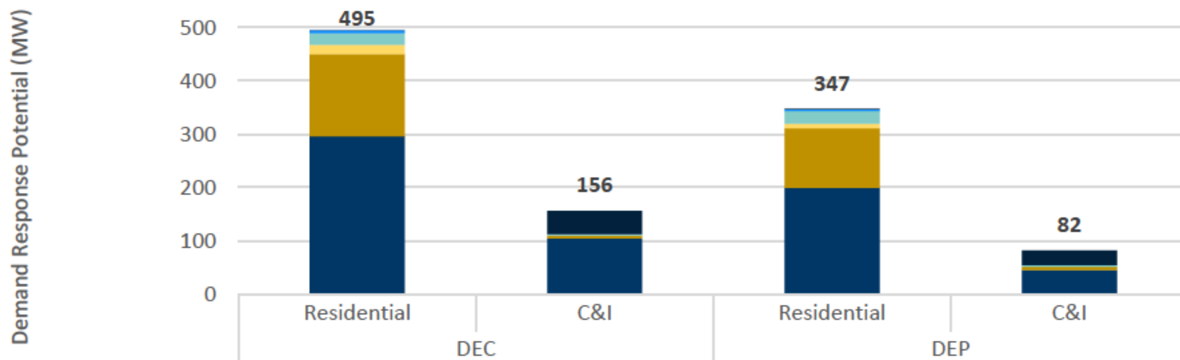
Figure 10 – DEP: Scenario Impact on Peak Day Load Shape (2031)



3.1 LOW SCENARIO

The Low scenario captures the DSM potential from two DSM rates options evaluated under the Flex Savings Options Pilot: TOU and TOU+CPP, in combination with the proposed set of mechanical solutions, thereby assessing rates that can be relatively quickly deployed. Figure 11 shows that DEC and DEP can respectively achieve 651 MW and 428 MW in winter peak reductions by 2041. Overall, the rate solutions and the residential Bring Your Own Thermostat (BYOT) program together account for more than 80% of the DSM potential.

Figure 11 – Low Scenario Achievable DSM Potential (2041) *



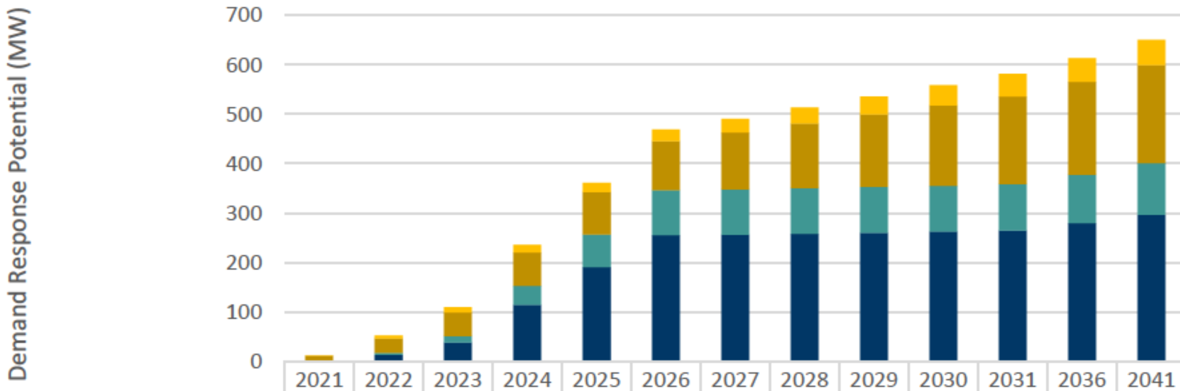
	Total	ADR	Battery Storage	HP Tune-Up	Rate-enabled T-stats	Rate-enabled HWH	BYOT	Rate Solution
DEC Residential	495		0.4	5	22	17	154	296
DEC C&I	156	43			3		5	105
DEP Residential	347		0.3	4	23	9	112	199
DEP C&I	82	27			3		6	45

* Due to rounding, numbers may not add up

Reviewing of the above chart, along with the detailed results provided in the appendix, a range of observations to focus on become apparent regarding future opportunities for Duke DSM programs. Although the TOU+CPP rate option accounts for 60% of the customer enrollment, it composed about 85% of the residential DSM rate savings, providing significantly more savings per customer than TOU. High savings from TOU+CPP participants are consistent with the preliminary results from the Flex Savings Options Pilot. Rate-enabled solutions, for both thermostats and water heaters account for a further 7% for the savings, reaching 72 MW in 2041. The residential BYOT program is already offered for summer peak reduction purposes and is in-process of being expanded to the winter season, offering an immediate expansion of winter peak reductions until new DSM rates can be successfully deployed.

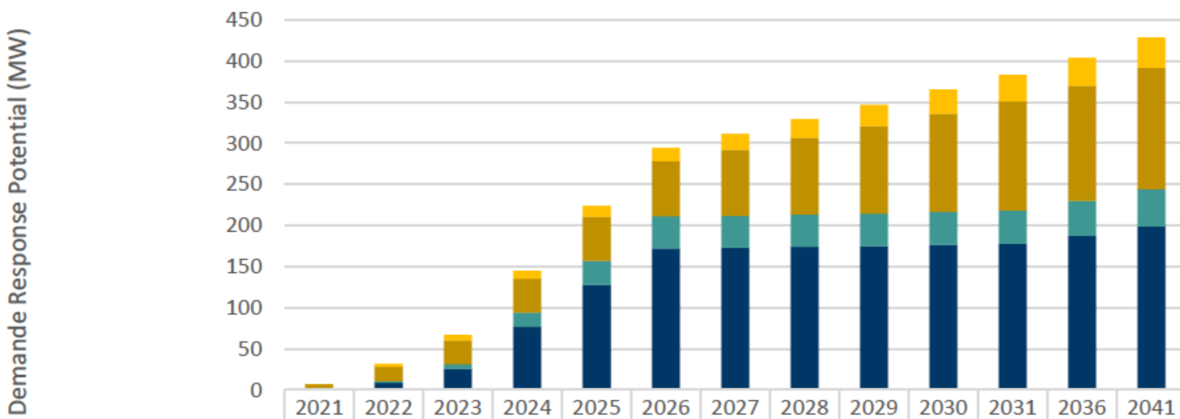
Figure 12 and Figure 13 below present the DSM solution ramp-up from 2021 to 2031, where all programs are at full deployment. The programs then continue to scale with load growth until 2041.

Figure 12 – DEC - Low Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	11	16	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	67	85	99	115	131	146	162	178	188	199
C&I - Rates	0.0	4.3	12.9	38.8	66.3	91.3	91.6	92.1	92.7	93.0	93.5	98.6	104.6
Residential - Rates	0	13	38	114	190	255	256	258	260	262	265	279	296

Figure 13 – DEP - Low Scenario Deployment

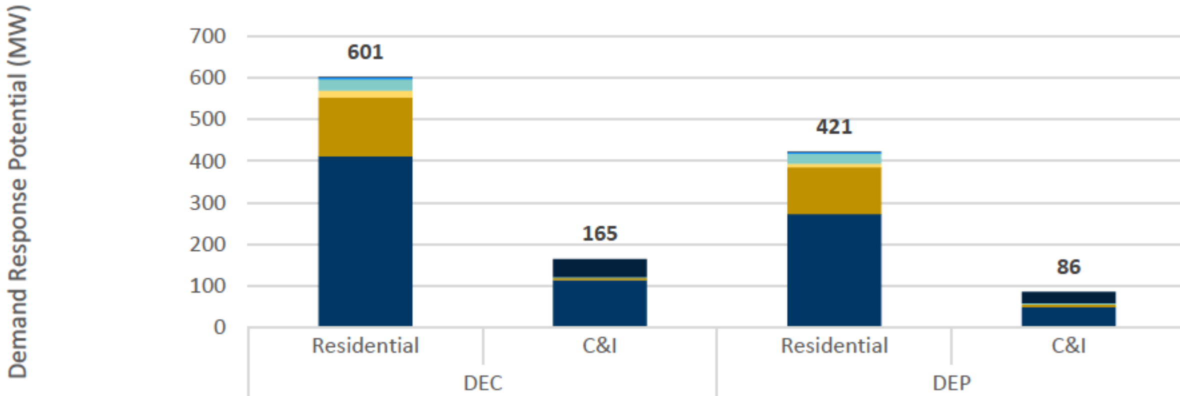


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	80	93	106	119	132	140	148
C&I - Rates	0.0	1.9	5.8	17.5	29.3	39.2	39.3	39.5	39.6	40.3	40.5	42.7	45.2
Residential - Rates	0	8	25	77	128	172	173	174	175	176	178	187	199

3.2 MID SCENARIO

The Mid scenario includes the DSM potential from the Low scenario, while adding a new residential rate option (Bill certainty with PTR) which targets risk averse customers. Adoption from small C&I is also increased, while PTR incentives for medium and large customers are doubled to $60/kW. Figure 14 below shows the breakdown of savings from the Mid scenario, wherein the overall achievable potentials for DEC and DEP in 2041 are 766 MW and 507 MW, respectively. With the addition of a new residential rate, rate solutions (residential and C&I) and BYOT now collectively account for over 85% of the DSM potential.

Figure 14 – Mid Scenario Demand Response Potential (2041) *



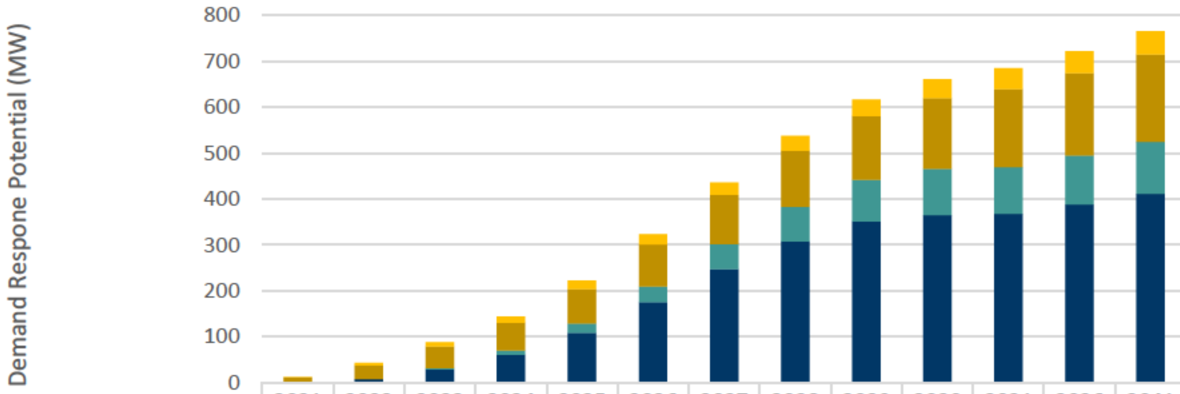
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	601	165	421	86
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	141	5	112	6
Rate Solution	411	113	272	49

* Due to rounding, numbers may not add up

The new Bill certainty with PTR rate option, accounts for a little under 30% of the residential rate savings potential and for most of the additional potential under residential rate solution in the Mid scenario. Despite the increase to the potential for the small C&I segment (i.e., from 9.0 MW in the Low scenario to 13.4 MW in the Mid scenario), overall, it has a limited impact on the total potential, which may not make this market segment a strong candidate for short-term program expansion. Finally, doubling the incentives to $60/kW for the medium and large C&I PTR program has limited impact, increasing the PTR potential by just 10%, while program costs increased by over 80%.

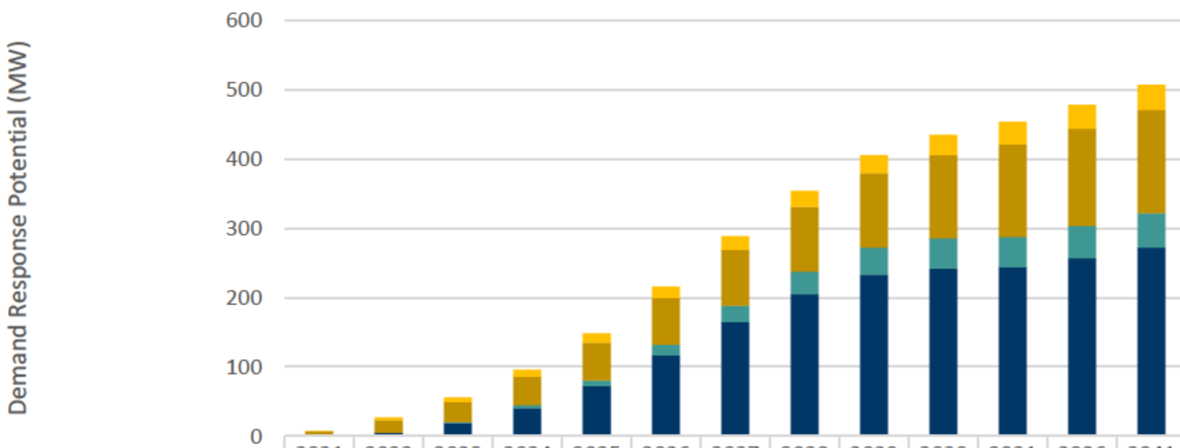
Figure 15 and Figure 16 below present the annual achievable potential, from 2021 to 2041. Program roll-out is extended compared to the Low scenario, to account for the time needed to implement the new rate option.

Figure 15 – DEC - Mid Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	60	75	91	107	123	138	154	170	179	190
C&I - Rates	0.0	0.0	2.9	9.8	19.7	34.6	54.7	74.9	90.4	101.0	101.4	106.9	113.4
Residential - Rates	0	8	28	61	109	175	247	308	351	364	368	388	411

Figure 16 – DEP - Mid Scenario Deployment

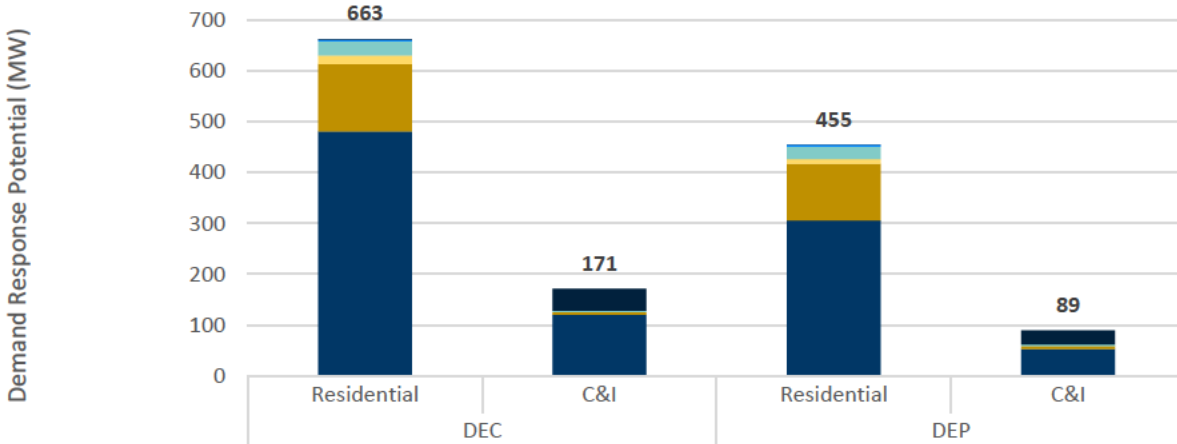


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0.0	0.0	1.3	4.3	8.6	15.1	23.8	32.6	39.3	43.9	44.0	46.4	49.2
Residential - Rates	0	5	19	40	72	117	165	205	233	242	244	257	272

3.3 MAX SCENARIO

The Max scenario aims to maximize the DSM rates potentials, and to assess the impact of offering the highest possible PTR incentives. A new CPP with flat volumetric rate is added to complement the residential rates included in the Mid scenario. In the Max scenario a complete set of residential rates options is offered ranging from low risk (Bill certainty with PTR) to high risk (TOU+CPP). In the C&I sector, the small C&I adoption was raised while incentives for medium and large C&I PTR were raised to their maximum level, while maintaining program cost-effectiveness. Figure 17 shows that DEC and DEP can respectively achieve 834 MW and 544 MW by 2041. With the addition of another new residential rate, collectively the rate solutions (residential and C&I) and BYOT now account for over 87% of the DSM potential.

Figure 17 – Max Scenario Demand Response Potential (2041) *



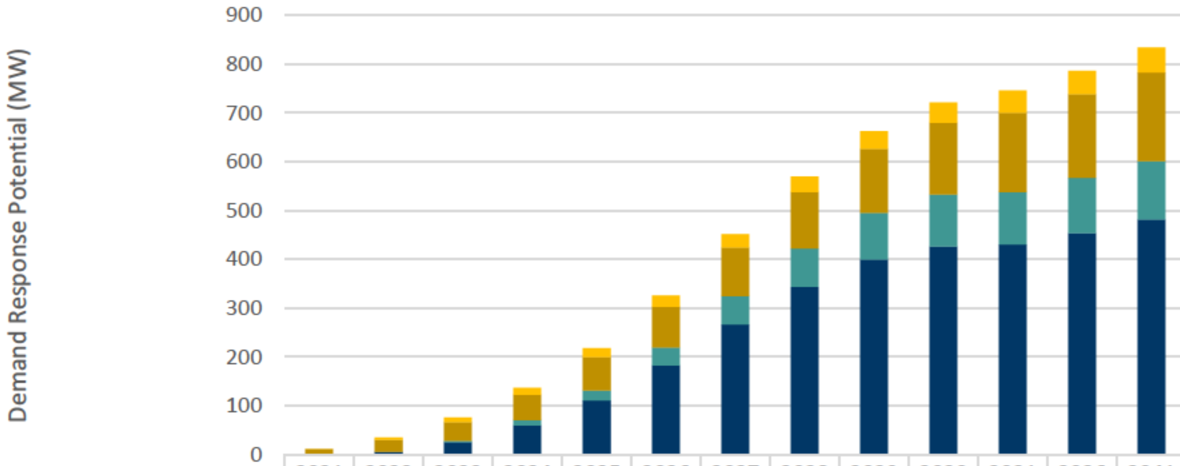
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	663	171	455	89
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	133	5	112	6
Rate Solution	481	120	306	53

* Due to rounding, numbers may not add up

Like the Mid scenario findings, the increase in adoption among small C&I customers and the increase in PTR incentives for the medium and large C&I customers resulted in limited additional uptake. The C&I sector potential reaches just 265 MW under the Max scenario (DEC and DEP combined) compared to the 241 MW in the Low scenario. The Max scenario residential rate potential presents a 39% increase over the Low scenario and a 17% increase compared to the Mid scenario. The breakdown of savings among the DSM rates is similar for both DEC and DE, with the TOU+CPP rate and Bill certainty with PTR each accounting for over 30% of the overall DSM rates savings.

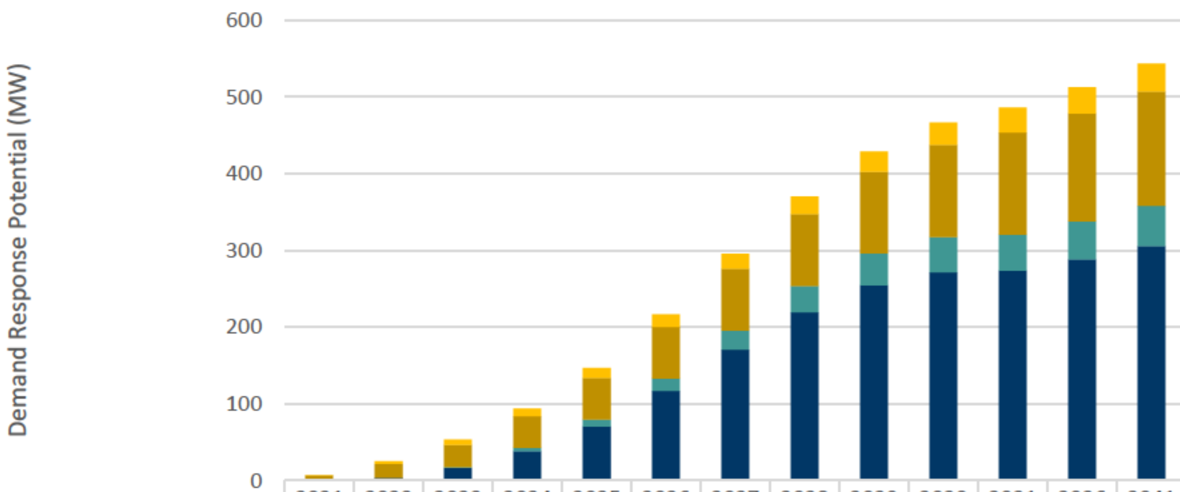
Figure 18 and Figure 19 below present the in each year from 2021 to 2041. As for the Mid scenario, program roll-out is extended to allow for the time needed to deploy additional new rate options.

Figure 18 – DEC - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	5	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	25	38	52	68	84	100	115	131	147	163	171	182
C&I - Rates	0	0	3	10	21	37	58	79	95	107	107	113	120
Residential - Rates	0	6	25	60	111	183	267	343	400	427	430	454	481

Figure 19 – DEP - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0	0	1	5	9	16	25	34	41	46	47	50	53
Residential - Rates	0	4	16	38	70	117	170	219	255	271	273	288	306

3.4 COMPARISON WITH DUKE'S MARKET POTENTIAL STUDY (MPS)

The goal of this study is to assess possible strategies that could allow Duke Energy to expand its winter peak reduction potential. To that end, it focuses on a small set of specific mechanical and rates solutions specifically selected for their ability to address winter peak loads. It is important to note that the study does not include all available mechanical solutions and therefore differs from the MPS conducted by

Nexant. Conversely, the MPS study focused on the achievable potential related to all mechanical solutions and did not assess any rate structure impacts.

Table 10 and Table 11 below show a high-level comparison between the MPS[12],[13] results and the modelled solution set. In both studies, the DSM potentials assessed are incremental to Duke's current winter peak DSM program impacts.

Table 10: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEC)

	DEC - 2041 Max Scenario	MPS – DEC (Base – 2041)	MPS – DEC (Enhanced – 2041)
Potential Total (MW)	**834**	**403**	**488**
C&I	Rates: 120	38	69
	Mechanical: 51		
Residential	Rates: 481	0	0
	Mechanical: 182	365	419

Table 11: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEP)

	DEP - 2041 Max Scenario	MPS – DEP (Base – 2041)	MPS – DEP (Enhanced – 2041)
Potential Total (MW)	**544**	**273**	**307**
C&I	Rates: 53	3	5
	Mechanical: 36		
Residential	Rates: 306	0	0
	Mechanical: 149	270	302

For the C&I market, this study estimates rate and mechanical potential separately and shows the impact mechanical solutions and rates not considered in the MPS and are therefore incremental to that study. For the residential sector, the potential in this study is also incremental to the MPS and outlines a plan to operationalize a more specific set of high value technologies and new rates not considered in the MPS. Additionally, the MPS excluded DSM rider opt-out customers while this study considers that a PTR rate structure could potentially attract some of those customers (between 5% and 9% depending on the rate class and scenario).

[12] DEC values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-21 DEC DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-20 DEC DSM Summer Peak Capacity Program Potential

[13] DEP values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-23 DEP DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-23 DEP DSM Summer Peak Capacity Program Potential

4 KEY TAKE-AWAYS

Based on the results of the winter peak demand reduction potential assessment, there is an apparent 1,378 MW (Max Scenario –DEC and DEP combined) of winter season DSM potential by 2041 representing 4.3% and 4.4% of the DEC and DEP forecasted load, respectively.

As shown in Table 12, most of this potential can be achieved via the residential sector using new rates and expanding mechanical solutions. A smaller portion of the DSM potential can be achieved by increasing incentives to drive program adoption and by diversifying rate structures.

Table 12 – Achievable DSM Potential in 2041, by Scenario (MW)

	Low Scenario	Mid Scenario	Max Scenario
Total Achievable Potential	**1,079 MW**	**1,273 MW**	**1,378 MW**
DEC Achievable Potential	651 MW (495 Res/156 C&I)	766 MW (601 Res/165 C&I)	834 MW (663 Res/171 C&I)
DEP Achievable Potential	428 MW (347 Res/82 C&I)	507 MW (421 Res/86 C&I)	544 MW (455 Res/89 C&I)

Table 13 below benchmarks the achievable DSM potential from the Mid and Max scenarios to DSM potential study findings in other jurisdictions. Overall, these show that the Duke DSM potential is like other winter peaking jurisdictions, where the industrial portion of the utility peak load is moderate and avoided costs are low, as is the case for Duke Energy.

Table 13 – Benchmarking of the Achievable DSM Potential (Mid-Max Scenarios) to Winter Peaking Jurisdictions

	Duke Energy (2020)	Newfoundland and Labrador (2019)	Puget Sound Energy (2017)	Northwest Power & Cons. Council (2014)
Portion of Peak Load	DEC: 4.0% - 4.3% DEP: 4.1% - 4.4% (2041)	10.4%[14] (15-year outlook)	3.7% (20-year outlook)	8.8% (15-year outlook)

Based on the findings in this report three key take-aways emerge:

- **Residential sector programs are key to achieve significant winter demand reduction potentials.** Across all scenarios, the residential sector shows three to four times more potential than the C&I

[14] The share of curtailable industrial load contributing to the utility peak load in Newfoundland and Labrador is high.

sector. This is driven primarily by seasonal variation in the residential sector demand curves, which results from the relatively high penetration of electric heating in the residential sector, while the C&I sector exhibits flatter variations on a daily and inter-seasonal basis.

Duke's current winter residential DSM offering is limited to DEP NC in the Company's Western Region service territory in the area surrounding Asheville[15] and the results of this study indicate that there is potential to expand residential Duke's winter DSM programs. Residential savings are derived from both mechanical and DSM rate solutions, and will likely take time to implement, in some cases requiring regulatory approval for new rates and pilots and programs.

- **Duke should consider pursuing some quick wins in the immediate term, followed by the addition of more complex and varied rate options.**

  On the residential side, a winter BYOT program can likely be implemented as the lowest-hanging fruit option, by adapting the existing summer peak BYOT program to include winter peak events.

  Following that, TOU and TOU+CPP rate designs could be implemented, pending positive results from the Flex Savings Options Pilot conclusions. Bill certainty + PTR and a Flat volumetric + CPP rate option can also be developed as near-term options to capture residential winter peak reduction potential.

  On the C&I side, implementing a PTR rate structure can achieve higher potential reduction than adding other new DSM programs. As a second step, adding Automated Demand Response solutions could enhance current DSM programs.

- **Changes to PTR incentive levels have very little impact on medium and large C&I customer potentials.** Most of the achievable DSM potential (91%) for medium and large customers is achievable with the low scenario incentives ($30 per kW).

Overall, it appears that expanding to new programs and rates could have an important role in increasing Duke winter peak DSM potential in both the DEC and DEP systems.

[15] This program, funded through Rider LC-WIN-2B, installs controls to (1) interrupt service to all resistance heating elements installed in approved central electric heat pump units with strip heat and/or (2) interrupt service to each installed, approved electric water heater. In addition, a winter BYOT filing has been made but has not yet been operationalized as of the time of this study being published

APPENDIX

A.1 RESULTS BREAKDOWN BY RATE CLASS

Table A-1 – Scenario 1 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	9	15	21	21	21	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	7	22	67	112	151	152	153	154	155	156	158	159	161	163	165	167	169	171	173	175
		Businesses	PTR - SGS	0.0	0.1	0.4	1.2	2.0	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0
			PTR - Medium and Large C&I	0	2	5	16	27	37	37	37	37	38	38	38	38	39	39	40	40	41	41	42	42
	DEC	Residential	TOU - RE	0	2	5	15	25	33	34	34	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	7	21	64	106	142	143	144	145	146	148	149	150	152	154	156	157	159	161	163	165
			TOU - RS	0.0	0.3	0.9	2.7	4.5	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	4	11	33	55	73	74	74	75	75	76	77	78	78	79	80	81	82	83	84	85
		Businesses	PTR - SGS	0.0	0.3	0.8	2.3	3.8	5.1	5.1	5.2	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			PTR - Medium and Large C&I	0	4	12	37	62	86	86	87	87	88	88	89	90	91	92	93	94	95	96	98	99
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	12	14	16	19	21	21	21	21	22	22	22	22	23	23	23
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	9	10	9	12	14	16	18	20	20	20	20	21	21	21	21	22	22	22
			Res. Wi-Fi T-Stat	11	23	37	51	67	80	91	103	115	126	138	139	141	142	144	146	147	149	151	153	154
			Res. HP Tune-up	0	1.6	2.0	2.4	2.7	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.5	3.8	5.2	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	1.1	1.5	1.8	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	2.0	2.7	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-2 – Scenario 2 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	2	4	7	11	16	19	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	4	15	30	52	83	114	138	154	155	156	158	159	161	163	165	167	169	171	173	175
			Bill Certainty + PTR - Res	0	0	2	6	13	22	35	48	58	65	66	66	67	68	69	69	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.1	0.4	0.8	1.4	2.2	3.0	3.6	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	36	40	40	40	41	41	42	42	43	43	44	44	45
	DEC	Residential	TOU - RE	0	1	3	7	12	18	25	30	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	4	14	28	50	78	107	130	145	146	148	149	150	152	154	156	157	159	161	163	165
			Bill Certainty + PTR - RE	0	0	2	8	15	27	43	59	71	80	80	81	82	83	84	85	86	87	88	89	90
			TOU - RS	0.0	0.2	0.6	1.2	2.1	3.3	4.5	5.5	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	2	7	15	26	40	55	67	75	75	76	77	78	78	79	80	81	82	83	84	85
			Bill Certainty + PTR - RS	0	0	1	2	4	8	12	17	20	22	23	23	23	23	24	24	24	24	25	25	25
		Businesses	PTR - SGS	0.0	0.0	0.2	0.8	1.5	2.7	4.2	5.8	7.0	7.9	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9
			PTR - Medium and Large C&I	0	0	3	9	18	32	51	69	83	93	93	94	95	96	97	99	100	101	102	103	104
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	23	36	46	58	69	81	92	103	115	126	127	128	130	131	133	135	136	138	140	141
			Res. HP Tune-up	0	1.6	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-3 – Scenario 3 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	6	10	16	23	27	30	31	31	31	31	32	32	33	33	33	34	34	35
			TOU+CPP - Res	0	3	9	18	32	51	69	84	94	95	95	96	97	98	99	101	102	103	104	106	107
			Bill Certainty + PTR - Res	0	0	2	8	16	27	43	59	72	80	81	82	83	83	84	85	86	87	89	90	91
			Flat Volumetric + CPP - Res	0	0	2	6	13	22	35	48	58	65	66	67	67	68	69	70	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.2	0.5	1.0	1.8	2.9	4.0	4.8	5.4	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.9	6.0	6.0	6.1
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	37	41	42	42	42	43	43	44	44	45	45	46	46
	DEC	Residential	TOU - RE	0	1	4	9	15	24	33	39	44	44	45	45	46	46	47	47	48	48	49	50	50
			TOU+CPP - RE	0	3	9	18	32	51	70	84	94	95	96	97	98	99	100	101	102	104	105	106	107
			Bill Certainty + PTR - RE	0	0	3	10	19	34	53	73	89	100	100	101	102	103	105	106	107	108	110	111	112
			Flat Volumetric + CPP - RE	0	0	3	8	17	30	47	64	78	87	88	89	90	91	92	93	94	95	96	98	99
			TOU - RS	0.0	0.2	0.6	1.3	2.3	3.6	4.9	5.9	6.6	6.7	6.7	6.8	6.9	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.5
			TOU+CPP - RS	0	1	4	9	16	25	34	41	46	46	46	47	47	48	48	49	50	50	51	51	52
			Bill Certainty + PTR - RS	0	0	1	3	6	10	16	21	26	29	29	30	30	30	31	31	31	32	32	32	33
			Flat Volumetric + CPP - RS	0	0	1	2	4	6	10	14	16	18	19	19	19	19	19	20	20	20	20	21	21
		Businesses	PTR - SGS	0.0	0.0	0.3	1.0	2.0	3.6	5.6	7.7	9.4	10.5	10.6	10.7	10.8	10.9	11.0	11.2	11.3	11.4	11.6	11.7	11.8
			PTR - Medium and Large C&I	0	0	3	9	19	33	52	72	86	96	97	98	98	100	101	102	103	104	106	107	108
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	2	4	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	19	29	39	51	62	73	85	96	107	119	120	121	122	123	125	126	128	130	131	133
			Res. HP Tune-up	0	1.3	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.4	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.3	0.7	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

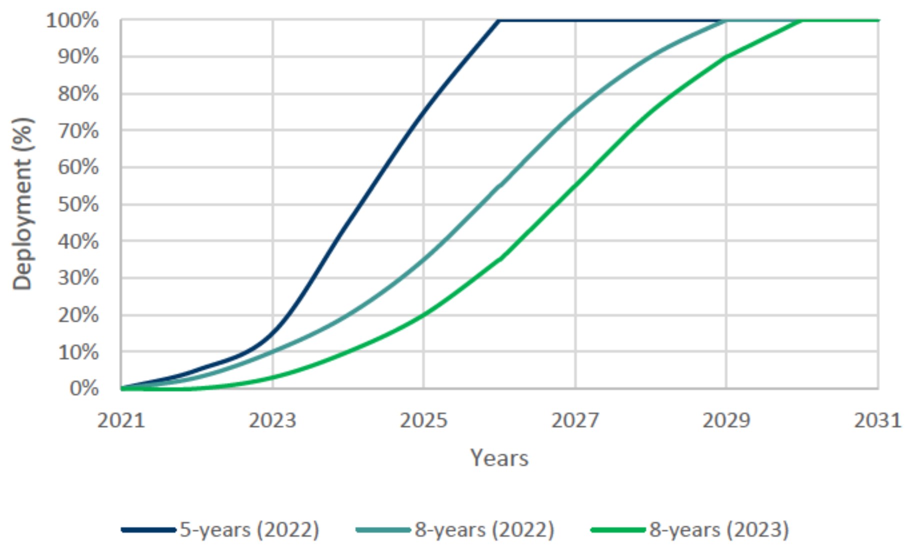
A.2 PROGRAM RAMP-UP AND COSTS

RAMP-UP

Ramp-up rates were created using s-curves over 5 and 8 years.

The low scenario, which is easier to implement, includes a ramp-up over 5 years. Scenarios Mid and Max, which requires more rates designs, assume a ramp-up over 8 years before full deployment of the rate solutions. Furthermore, rates that where included in the pilot (TOU and TOU+CPP) are estimated to launch in 2022, while bill certainty + PTR and flat volumetric + CPP are starting in 2023. The figure below summarized the ramp-up.

Figure A-1 – Enrollment Ramp-up: Rates



PROGRAM COSTS

Estimated program costs for the mechanical solution set are presented in the table below.

Table A-4: Program Costs

Program Name	Development Costs	Program Fixed Annual Costs	Other Costs ($/customers) for marketing, IT, admin
Residential Rate-Enabled T-Stat	$200,000	$100,000	$40
Residential BYOT	$100,000	$100,000	$40
Residential Rate-Enabled HWH	$175,000	$75,000	$35
WP/HP Tune-up	$175,000	$100,000	$0
Commercial Rate-Enabled T-Stat	$150,000	$75,000	$40
Commercial BYOT	$75,000	$75,000	$40
Residential BYOB	$100,000	$100,000	$30
ADR	$250,000	$150,000	$20

A.3 KEY ASSUMPTIONS

ECONOMIC ASSUMPTIONS

The avoided costs provided by Dukes for South and North Carolina were blended between South and North Carolinas to obtain an average avoided cost for each system. These avoided costs are presented in the table below, in 2021 dollars. This study uses also uses blended discount rates of 6.9% (DEC) and 6.8% (DEP).

Table A-5 – Avoided Costs - CONFIDENTIAL

Year	DEC - Avoided cost ($/kW)	DEP - Avoided cost ($/kW)
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]
2043	[redacted]	[redacted]
2044	[redacted]	[redacted]
2045	[redacted]	[redacted]

SEGMENTATION AND END USE

The follow ratios where used to breakdown the potential by State.

Table A-6 – Segmentation by State

State	DEC	DEP
North Carolina	73.50%	85%
South Carolina	26.50%	15%

To obtain a breakdown per rate and per end use, the latest EIA's CBECS (2012) and RECS (2015) data was used. This data was combined with Duke's 2017 and 2018 annual consumption and average consumption per customer for each rate class to obtain the following tables.

Table A-7 – DEC segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	18,049	324,972
LGS	64%	78%	536,989	11,431
OPTC	64%	78%	745,677	21,133
OPTI	64%	78%	11,394,026	1,642
Other	64%	78%	412,306	7005
RS	24%	52%	12,866	1,295,393
RE	100%	100%	13,485	946,860

Table A-8 – DEP segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	14,379	201,554
MGS	64%	78%	372,588	33,267
LGS	64%	78%	17,371,855	255
RTP	64%	78%	68,103,493	90
Other	64%	78%	62,518	1159.44
Res	63%	72%	13,951	1,322,187

The EIA's building archetypes where used to generate 8760h annual load curve to model consumption for each rate class.

Table A-9 – DEC building archetypes included per rates

EIA's Archetypes	Segment						
	RS	RE	SGS	LGS	OPTC	OPTI	Other
Hospital	-	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	-	Yes	-	-	-	-
Industrial	-	-	-	Yes	Yes	Yes	Yes
MF_Elec. Resistance	Yes	Yes	-	-	-	-	-
MF_HP	Yes	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes	Yes
Office Medium	-	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	-	Yes	-	-	-	-
Outpatient Healthcare	-	-	Yes	-	-	-	-
Restaurant Fast Food	-	-	Yes	-	-	-	-
Restaurant Sit Down	-	-	Yes	-	-	-	-
Retail Standalone	-	-	Yes	-	-	-	-
Retail Strip Mall	-	-	Yes	-	-	-	-
School Primary		-	-	Yes	Yes	Yes	Yes
School Secondary	-	-	-	Yes	Yes	Yes	Yes
SF_Elec. Resistance	Yes	Yes	-	-	-	-	-
SF_HP	Yes	Yes	-	-	-	-	-
Supermarket	-	-	-	Yes	Yes	Yes	Yes
Warehouse	-	-	Yes	Yes	Yes	Yes	Yes

Table A-10 – DEP building archetypes included per rates

EIA's Archetypes	Segment					
	Res	SGS	MGS	LGS	RTP	Other
Hospital	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	Yes	Yes	-	-	-
Industrial	-	-	-	Yes	Yes	Yes
MF_Elec. Resistance	Yes	-	-	-	-	-
MF_HP	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes
Office Medium	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	Yes	-	-	-	-
Outpatient Healthcare	-	Yes	Yes	-	-	-
Restaurant Fast Food	-	Yes	Yes	-	-	-
Restaurant Sit Down	-	Yes	Yes	-	-	-
Retail Standalone	-	Yes	-	-	-	-
Retail Strip Mall	-	Yes	-	-	-	-
School Primary		-	Yes	Yes	-	Yes
School Secondary	-	-	Yes	Yes	-	Yes
SF_Elec. Resistance	Yes	-	-	-	-	-
SF_HP	Yes	-	-	-	-	-
Supermarket	-	-	Yes	Yes	Yes	Yes
Warehouse	-	Yes	Yes	Yes	Yes	Yes

RESIDENTIAL RATE DETAILS

TOU RATES

This rate targets consumers able to vary their daily usage to reduce energy costs. This new TOU structure is based on the Flex Savings Options pilot conducted by Nexant for Duke Energy Carolinas (NC). The pilot went into effect on October 1, 2019 and preliminary results were provided by Duke to inform our analysis. The pilot tested three different rates structures (TOU, CPP, TOUD) across three customer classes including all-electric residential (RE) and standard residential (RS).

- **Peak to off-peak ratio:** 1.7
- **Peak load impact**
    - Based on preliminary Flex Savings Options Pilot findings
    - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
    - Customers in either DEC – RE, DEC – RS or DEP – Res

TOU WITH CPP

This rate targets consumers who are highly attentive to their energy demand and can change their load in a significant manner. The modelled TOU with CPP rate structure is also based on the Flex Savings Options Pilot. Customers are on the previous TOU rate but with higher hourly prices during specific peak hours on about 20 days per year.

- **CPP Peak to off-peak ratios:** 3.2
- **Peak load impact**
    - Based on the preliminary Flex Savings Options Pilot findings
    - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
    - Customers in either DEC – RE, DEC – RS or DEP – Res

BILL CERTAINTY WITH PTR

This rate targets consumers who want to mitigate their billing risk. It offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
    - 3:1 savings ratio for all rates[16]
    - Bill certainty is not expected to increase the winter peak demand compared to a flat volumetric rate
- **Peak load impact**
    - Peak impact reduction was derived from the Arcturus[17] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.

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[16] For example: With an average cost of electricity over the fixed bill is 15¢/kWh, the rebate would be 30¢/kWh, for a total discount of 45¢/kWh, which is three times to initial cost of electricity.

[17] Peak reduction from "Arcturus 2.0: A meta-analysis of time-varying rates for electricity", A. Faruqui, S. Sergici and C. Warner, 2017.

- Bounce back effects are derived from the Flex Savings Options Pilot findings (CPP), adjusted for savings.
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

FLAT VOLUMETRIC WITH CPP

This rate targets consumers who can change their load in a significant manner but are not willing to modify their everyday usage. It offers a fixed price per unit of energy consumed, with a CPP on peak days.

- **CPP peak to off-peak ratios:** 5.5
- **Peak load impact**
  - Based on the Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

It is important to note that all customers who are enrolled in one of the residential rates above and a rate-enabled mechanical solution (rate-enabled thermostats or hot water heater) have a reduced peak load impact, based on the peak load end use share of heating and hot water usage, to account for the fact that the load impact is considered in mechanical solutions, preventing any double counting.

NON-RESIDENTIAL RATES DETAILS

SMALL C&I CUSTOMERS – BILL CERTAINTY WITH PTR

Being a segment with historically low elasticity to electric demand, this rate was implemented as being the most consumer friendly, hoping to spur demand response. The rate offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
  - 3:1 saving ratio[18]
  - Peak impact reduction was also derived from the Arcturus[19] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.
  - Bounce back effects apply the residential PTR shape, adjusted to savings levels derived for C&I customers.
- **Eligible Market**
  - Customers in either DEC – SGS or DEP – SGS

Although the Flex Savings Options Pilot also included customers from the SGS rate class, results were not yet available to integrate into our analysis. Instead, the Arcturus report was used, but savings were

[18] For example: With an average cost of electricity over the fixed bill is 15¢/kWh, the rebate would be 30¢/kWh, for a total discount of 45¢/kWh, which is three times to initial cost of electricity.

[19] Peak reduction from "Arcturus 2.0: A meta-analysis of time-varying rates for electricity", A. Faruqui, S. Sergici and C. Warner, 2017.

reduced by 50% compared to residential customer response to account for the historically low elasticity of the small C&I sector.

MEDIUM AND LARGE C&I RATES – PTR

By using a carrot-only rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times.

- **Peak load impact**
  - Peak impact reduction was assessed based on an end-use approach where the percentage of achievable load curtailable by customer was evaluated for each major end-use. Baseline load curves are based on hourly average demand per customer class provided by Duke Energy.
- **Eligible Market**
  - All C&I customers can choose to enroll (DEC – LGS, DEC – OPTC, DEC-OPTI, DEC – Other, DEP MGS, DEP – LGS). It is assumed that a small portion of opt-out customers would choose to enroll in the rates (more details in the results section)
  - For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count.