DUKE ENERGY

Winter Peak Targeted DSM Plan

December 2020

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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)

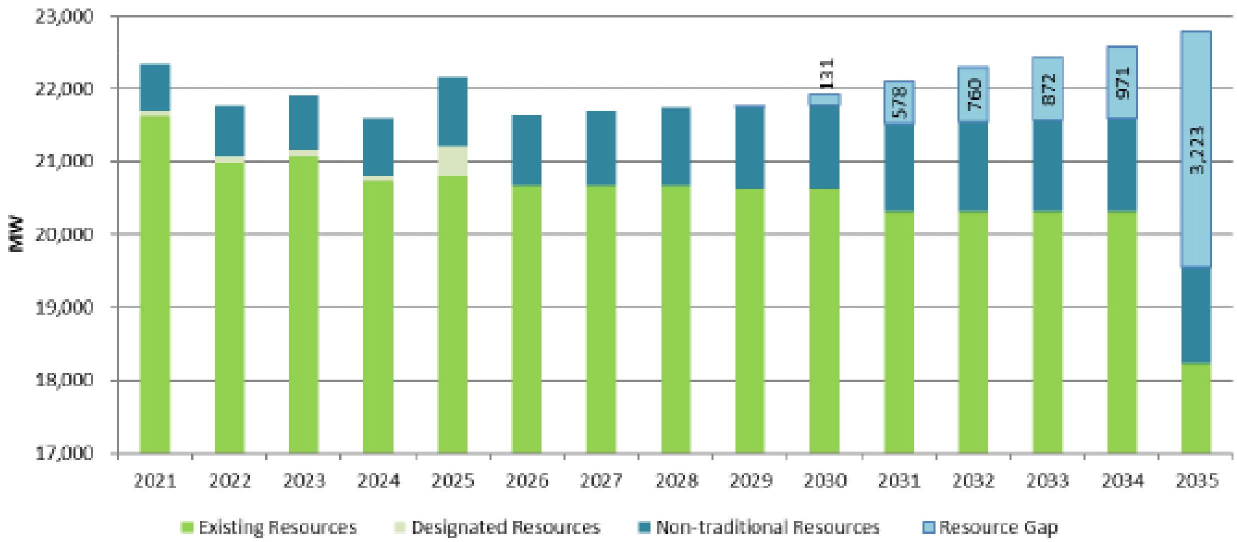
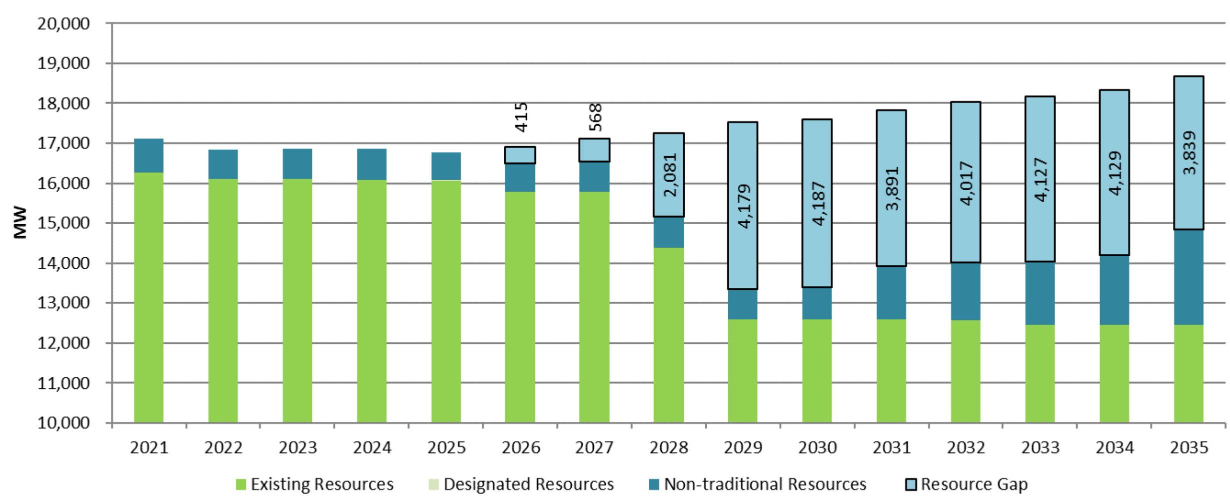


Figure 2. DEP Base Case with Carbon Policy Load Resource Balance (Winter)



- 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

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[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: o 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. o 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. o 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: o A menu of multiple but distinct rate options. o Clear, easy-to-understand messaging about rate options available. o Online tools and calculators to help customers choose their optimal rate. o Technical support from staff specifically trained to resolve rate questions. o 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

[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

[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.

[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

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[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: ○ 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. ○ 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. ○ 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. – Example incentive levels for this program, including both new and existing Duke incentives include: ○ Winter HVAC Tune-Up: Customer discounted price of $99/unit, and Contractor Incentive of $75/unit. ○ Adjusting/Re-wiring heat strips: Customer rebate of $75/unit, and Contractor $25/unit. ○ Install outdoor thermostat: Customer rebate of $75 rebate/unit, and Contractor $25/unit. ○ Smart thermostat: Customer rebate of $50/unit. ○ 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

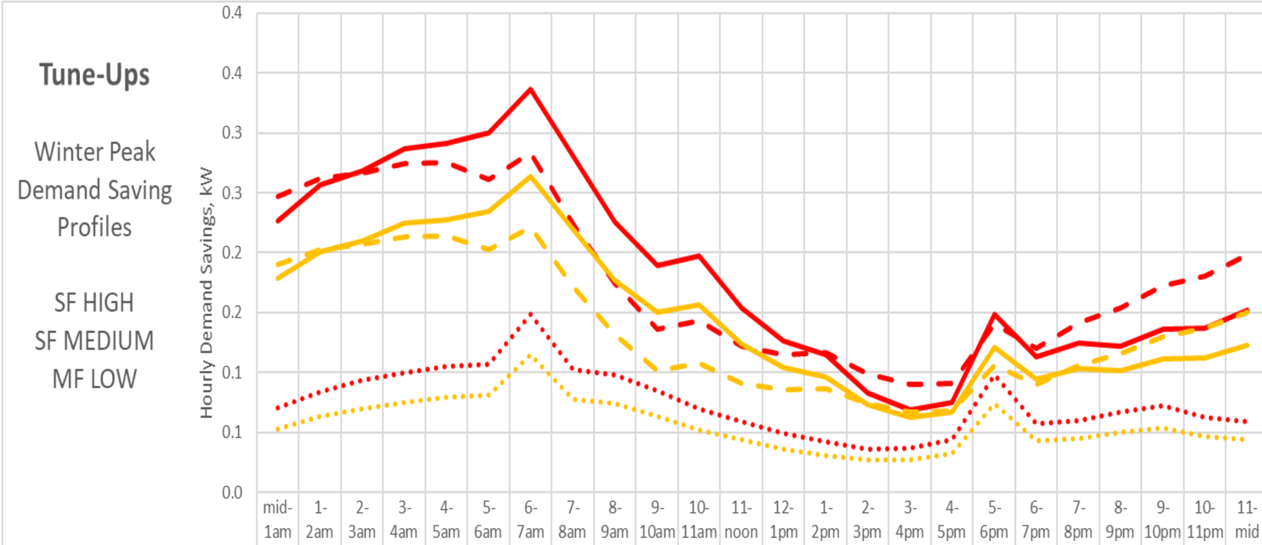
3.4.12 Energy Impacts and Winter Peak Demand Savings

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

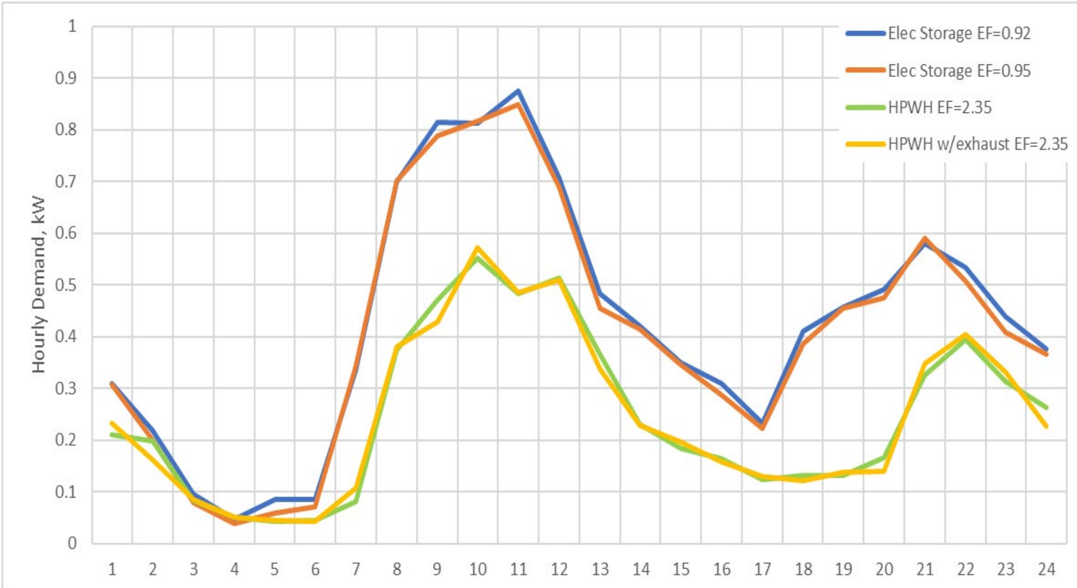


Figure 5 and Figure 6 illustrate the average daily hot water use for a 3-bedroom, 2 bath single family residence, including effects on space heating, during a 3-hour water heating control load shifting event. These figures show that water heaters typically operate in maintenance heat mode (i.e., prior 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

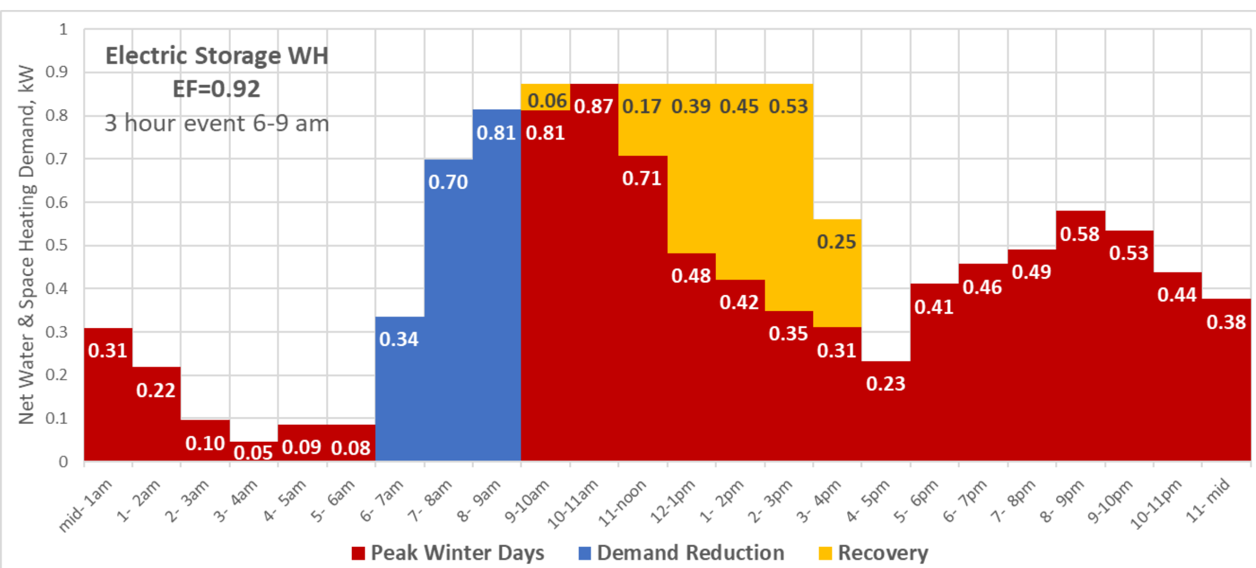
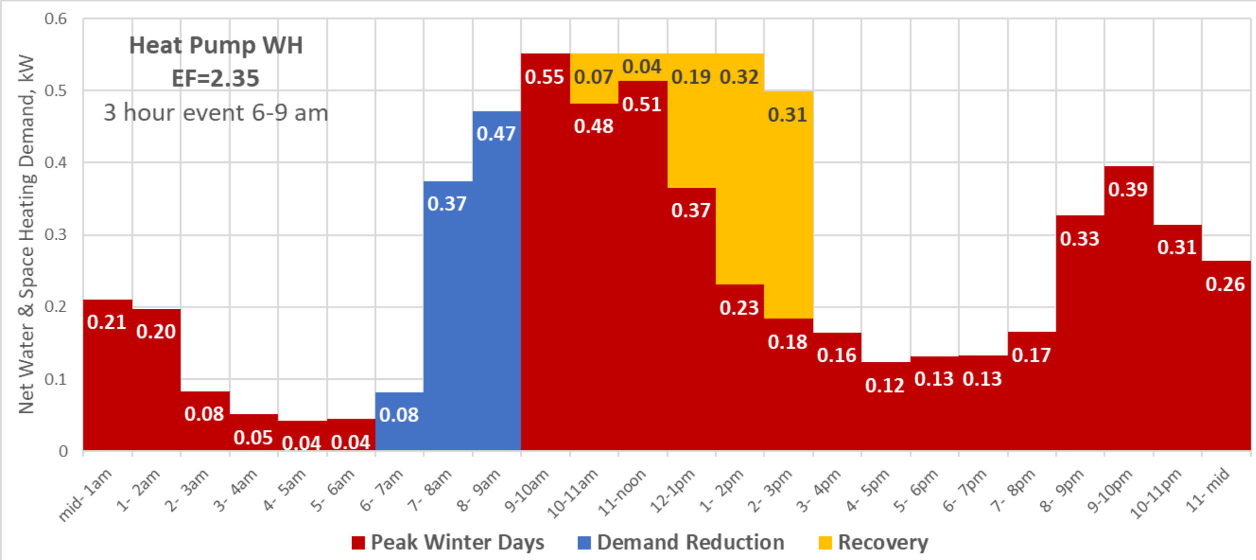


Figure 6. Modelled Heat Pump Water Heater Peak Load Shed Profile



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

[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

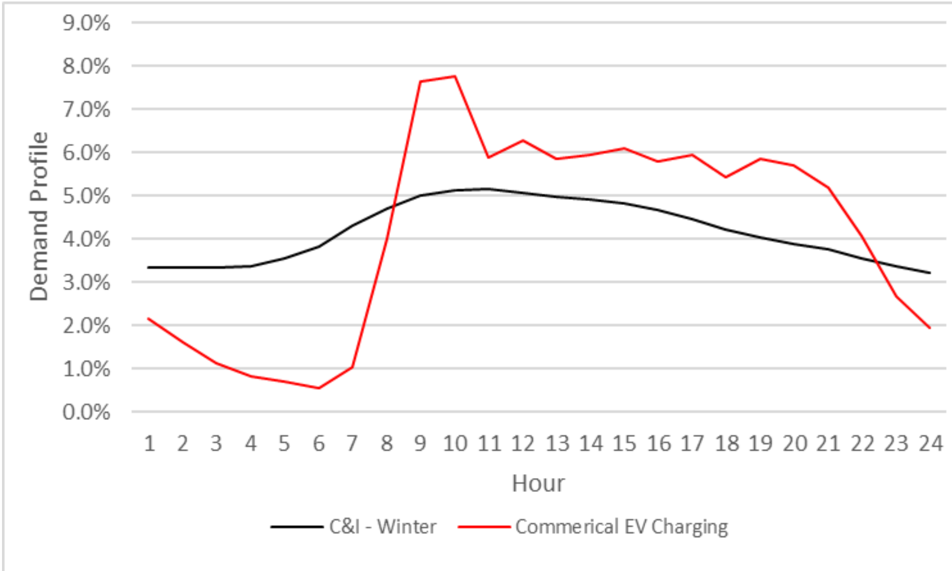
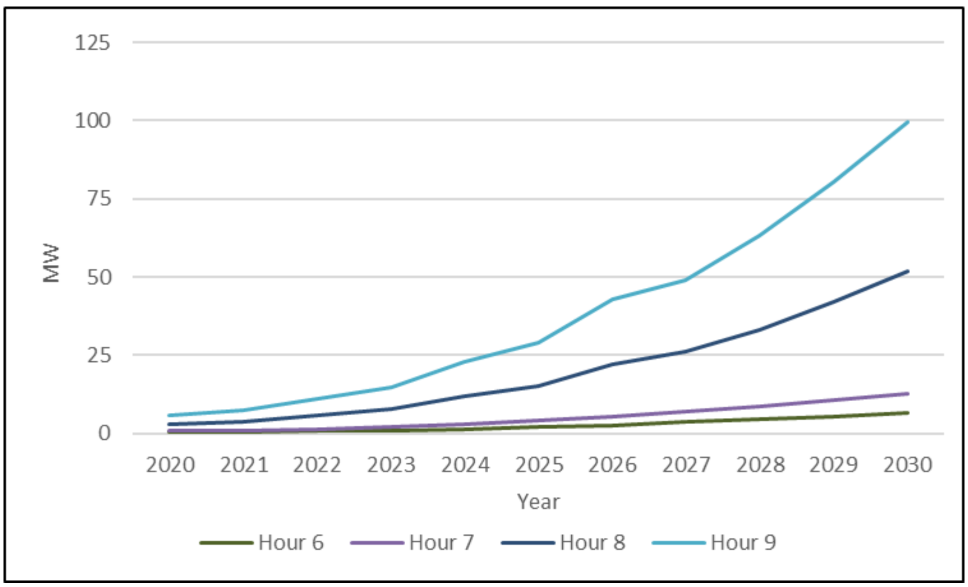


Figure 8. EV Charging Load Forecast by Morning Hour



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

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[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